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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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Application of Pacific Gas and Electric Company (U 39-E) for Approval of Demand Response Programs, Pilots and Budgets for Program Years 2018-2022.	Application 17-01-___ (Filed January 17, 2017)

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U 39-E) FOR APPROVAL OF DEMAND RESPONSE PROGRAMS, PILOTS AND BUDGETS FOR 2018-2022

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Pacific Gas and Electric Company (PG&E) submits this application for approval of its demand response (DR) programs, pilots, and budget for 2018-2022.[1/]

I. INTRODUCTION AND SUMMARY OF APPLICATION

PG&E's 2018-2022 Demand Response Application (Application) builds on its 2012-2017 programs, addresses key principles identified by the Commission in Decision (D.) 16-09-056 (Guidance Decision), and takes steps toward supporting the continued evolution of DR programs.

In 2016, PG&E intensified its efforts to integrate its existing DR programs into the California Independent System Operator (CAISO) markets.[2/] Consistent with the Guidance Decision, this Application focuses on these existing PG&E-implemented programs, pilots, and technology initiatives, and on PG&E's continuing CAISO integration efforts. PG&E proposes improvements to its Capacity Bidding Program (CBP), Base Interruptible Program (BIP), SmartAC™ Program, and Automated Demand Response (ADR) Program. These improvements

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1/ PG&E's Application is filed pursuant to the Commission's Rules of Practice and Procedure, Rules 2.1–2.3, 3.2, and 7.1, and *Decision Adopting Guidance for Future Demand Response Portfolios and Modifying Decision 14-12-024,* D. 16-09-056, pp. 3, 60, 97 (Ordering Paragraph (OP) 6).

2/ D.14-12-024, OP 4.a ruled that beginning on January 1, 2018, any DR that does not reduce the Resource Adequacy requirement must be integrated into the CAISO market to receive Resource Adequacy value.

will allow PG&E to reliably and cost-effectively meet the needs of the grid, further support the enablement of a vibrant third-party market, and better serve customers.

A. Foundational Principles Supporting the 2018-2022 DR Application

PG&E's 2018-2022 DR Application is based on five foundational principles that are summarized below and explained in more detail in Chapter 1 of PG&E's Opening Testimony.

1. Proposed DR Programs Must Effectively Meet Evolving Grid Needs

This principle is aligned with the Guidance Decision's principle that DR shall evolve to complement the continuously changing needs of the grid.[3/] In addition to addressing System and Local Resource Adequacy (RA) needs, PG&E's proposed improvements to its existing programs also address renewables integration. PG&E defers program revisions pertaining to distribution uses that are pending resolution of the Electric Distribution Resource Plan (DRP) (R.14-08-013) and the Integrated Distributed Energy Resource (IDER) (R.14-10-003) proceedings, and also defers issues addressed in the nascent Integrated Resource Planning (IRP) proceeding (R.16-02-007). PG&E acknowledges that these proceedings are expected to further shape the role of DR in meeting grid needs and expects to address related program design revisions in future DR applications.

Renewables Integration: As California's Renewables Portfolio Standard and greenhouse gas emission reduction requirements are increasing, the locations, seasons, and hours when DR is most valuable to the grid are changing. DR traditionally has been designed to meet requirements established by the current RA measurement hours of 1:00 p.m.-6:00 p.m. during summer months and 4:00 p.m.-9:00 p.m. during winter months. These hours were meant to address system gross peak load conditions. However, net system peak load hours are expected to shift later in the day over the next several years. PG&E expects that, in the future, DR will provide most value to the electric grid between the hours of 4:00 p.m. and 10:00 p.m. year-

3/ D. 16-09-056, pp. 46, 97 (OP 8).

round. This period generally coincides with the start of the end-of-day upward ramp as solar resources decline, through the end of the night-time peak.

Due to this and in anticipation of a shift in RA measurement hours, PG&E is proposing a new "Elect+" option to its CBP. This option will give customers and aggregators an opportunity to test dispatch during these new times of value, while the DR will still be available during current RA measurement hours.

Distribution Services: As described in the Guidance Decision, the DRP and IDER proceedings will determine the value of distribution services to the grid and establish a distributed energy resource (DER) sourcing framework.[4/] Because these proceedings have not yet determined the sourcing framework or how DR programs will be integrated into that framework, PG&E proposes no changes to its programs that specifically address distribution system needs. However, PG&E's SmartAC™ program and BIP currently allow PG&E to call the resources to address distribution reliability needs, and PG&E proposes to continue this practice in this Application.

2. DR Programs Should Enable Choice and Flexibility in How Customers and Aggregators Can Participate in DR in Order to Unlock More Opportunities to Serve Grid Needs

In light of the importance placed by the Guidance Decision on customer choice of DR options,[5/] PG&E proposes to enable greater choice and flexibility in how customers can participate in DR by scaling the findings of the Supply Side DR Pilot into new "Elect" and "Elect+" options for its CBP. These options will offer customers and aggregators the option to elect an availability for, and opportunity cost of, providing DR that reflects underlying customer capabilities, in addition to meeting Commission and CAISO requirements for RA resources.

4/ *Id.,* p. 9.
For purposes of this Application and accompanying PG&E's Opening Testimony, distributed energy resource (DER) refers to "distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies." Public Utilities Code section 769(a).

5/ D.16-09-056, pp. 46, 52, 90 (Finding of Fact 83), 97 (OP 8).

In addition to providing more flexibility to CBP customers and aggregators, PG&E also proposes a broader array of choices for residential DR to increase participation rates, including continued operation of PG&E's SmartAC™ program for residential customers who prefer to directly enroll with PG&E, and the opening of all CBP options to aggregators of residential customers. This CBP choice will support the growth of the residential DR market by adding another program channel for residential aggregators outside of the Demand Response Auction Mechanism (DRAM).

3. PG&E's Roles and Responsibilities in Supporting the Growth of DR in California are Different from Those of Third Parties

PG&E's proposed portfolio conforms to the Guidance Decision's instruction to improve customer choice and improve the level of competition for third-party DR providers.[6/] The Decision determined that it is "reasonable to continue both roles of the IOUs [investor-owned utilities] as demand response program providers (implementers) and administrators" and that IOUs should compete to enroll customers in their demand response programs.[7/]

PG&E's proposed portfolio does not necessarily compete directly with third-party DR provider programs. Instead, PG&E proposes a complementary portfolio that presents increased options for third-party aggregators, DR providers, and, ultimately, customers. For example, PG&E's aggregator programs (CBP and BIP) provide an option for third-party aggregators that do not want to manage all DR provider and Scheduling Coordinator functions necessary to integrate with the CAISO markets. These aggregator programs also can function as a "parking lot" for third-party DR providers to manage the customers within their portfolio, creating added flexibility to maximize the return on their recruitment efforts. For example, during periods when a third-party DR provider does not have a DRAM contract or has a fully subscribed DRAM contract, it can choose to enroll its customers into the CBP or BIP as an aggregator, until it is awarded another DRAM contract to which it can move those customers.

6/ *Id.,* p.56.
7/ *Id.,* pp. 52, 56, 67, 90 (Finding of Fact 83).

It also is important to note that third-party DR providers are free to enroll the customers and resources that are most attractive to them, and are free to offer different contract terms to individual customers depending on the customers' interest in working with a DR provider. PG&E's programs that offer direct enrollment will remain open to customers who prefer working with the utility or who may not be good candidates to work with third-party DR providers. By providing more avenues for customer enrollment, overall participation in DR is more likely to grow.

4. PG&E Remains Committed to Third-Party Direct Participation and to Accelerating and Expanding Rule 24 Implementation

PG&E is committed to supporting the Commission's goal of increasing the role of third-party DR providers by accelerating the expansion of Electric Rule 24 (Rule 24) for DRAM and non-DRAM participants.

Given the Guidance Decision directive that PG&E procure up to 400 MW of DR through the DRAM if or when it becomes a full program in 2020,[8/] Rule 24 mass market implementation[9/] will be necessary by June 2019 to allow time for registration prior to the IOU year-ahead RA filings and the deadline for monthly supply plan submittals. Otherwise, there may not be a sufficient number of Rule 24 registrations available for the DR providers. PG&E has raised this issue because it is concerned that the increase to approximately 75,000 Rule 24 registrations, pursuant to the advice letter due February 7, 2017,[10/] may not provide a sufficient number of Rule 24 registrations for DRAM levels in 2020 and beyond.

PG&E notes that, under the filing procedures approved in D.15-03-042 and D.16-06-008, there may not be sufficient time for the Commission to approve a PG&E funding request for Rule 24 mass market implementation by June 2019 for the 2020 DRAM. PG&E has consistently

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8/ *Id.*, p. 74.

9/ Rule 24 mass market implementation will involve (1) enabling a click-through process for electronic signatures of the Customer Information Service Requests (CISR) permitting IOUs to release information DR providers, (2) IOU processing of the completed CISR forms to release information, and (3) CAISO registration of up to 300,000 service account registrations.

10/ Draft Resolution E-4817 (published Dec. 15, 2016).

estimated that it will require 12-18 months to implement Rule 24 mass market implementation once the Commission approves PG&E's application. PG&E also estimates that approximately 12 months will be needed to file this Application and receive a Commission decision, if it is not litigated. So, for PG&E to complete mass market implementation by June 2019, it would have to submit its application by approximately March 2017. As explained in Chapter 3 of its Opening Testimony, PG&E has initiated a process through a petition for modification (PFM) of D.16-06-008 and D.15-03-042 on January 3, 2017 to potentially shorten the timeline and enable additional flexibility for PG&E to have Rule 24 mass implementation completed. If the Commission promptly approves the mass market implementation Tier 3 advice letter or application, including its funding request, PG&E may have a better opportunity to complete Rule 24 mass market implementation in time for the 2020 DRAM. In the meantime, draft Resolution E-4817 has directed PG&E and the other IOUs to submit an advice letter by February 7, 2017 to aggressively increase customer registrations in advance of the 2018-2019 DRAM pilot.[11/] PG&E plans to submit a Tier 3 advice letter seeking authority to increase its Rule 24 capabilities to a total of 75,000 registrations, beyond the 40,000-registration intermediate implementation step that was approved in D.16-06-008 and that PG&E plans to complete by March 2017.[12/]

5. DR Programs Should Be an Enablement Platform That Transforms End-Use Loads Into Grid-Responsive Loads, Rather Than Tied to Specific End-Uses

Many behind-the-meter (BTM) DER technologies have the potential to provide DR by temporarily dropping or shifting load to help realign supply and demand, and to reduce the customer's utility bill. These include energy efficient devices like programmable controllable thermostats, energy storage devices, electric vehicles (EV), and EV charging stations. BTM DER technology can be utilized to maximize the customer's benefit, which may not align with maximizing benefit to the electric grid. If enrolled in a DR program, however – whether through

11/ Draft Resolution E-4817, OP 5.

12/ As directed in D.16-06-008, OP 13, PG&E may request up to $10.39 million to increase customer registrations in the CAISO via a Tier 3 advice letter.

PG&E or through a third party – the BTM DER is incentivized to dispatch when needed by the grid. Because of this, PG&E sees DR programs and DR enabling technologies, such as ADR, as a platform that supports and incentivizes customers in transforming their BTM end-use technologies into grid-responsive loads to serve the evolving needs of the grid. On the other hand, DER technology programs, such as the Self-Generation Incentive Program and certain energy efficiency programs, encourage the adoption of DER end-uses for reasons apart from serving the grid by temporarily dropping or shifting load.

B. Estimated Load Impact of Demand Response Portfolio.

PG&E's load impact analysis contained in Chapter 5, Table 5-3, of its Opening Testimony indicates the following portfolio size, based on *ex ante* load impacts for August 2018-2022:

TABLE 1
PACIFIC GAS AND ELECTRIC COMPANY
PORTFOLIO-ADJUSTED EX ANTE LOAD IMPACTS (MW) FOR AUGUST
UNDER PG&E PEAKING CONDITIONS AND 1-IN-2 WEATHER FOR 2018-2022

DR Resource	2018	2019	2020	2021	2022
Base Interruptible Program	330	330	330	330	330
Capacity Bidding Program	49	52	56	59	62
Peak Day Pricing	54	54	55	55	55
Permanent Load Shift	3	3	3	2	2
SmartAC™	72	74	76	79	81
SmartRate™	22	22	22	22	22
Total MW Annually	**529**	**535**	**541**	**546**	**552**

C. Summary of PG&E's Proposed Improvements to Existing PG&E Implemented Programs and Pilots.

PG&E proposes the following primary improvements to its existing DR programs and pilots for 2018-2022,[13/] in accordance with the guiding principles discussed in the Section A above. PG&E also builds upon the improvements approved in the Commission's *Decision*

13/ *See* PG&E Opening Testimony, Chapter 2.

Adopting Bridge Funding for the 2017 Demand Response Programs and Activities.[14/] The program components discussed are:

- Base Interruptible Program,
- SmartAC™,
- Capacity Bidding Program,
- Load Modifying Resource DR,
- Emergency DR Cap,
- Dual Participation,
- Prohibited Resources,
- DR Enabling Technologies,
- Pilots, and
- Marketing, Education, Outreach and Training.

1. **Base Interruptible Program.** BIP is a statewide DR program that is operated year-round. PG&E proposes to increase the maximum event duration from four hours to six hours, to align PG&E's BIP with the other IOUs' BIP and to meet the reliability needs of the grid. According to the E3's Renewable Energy Capacity Planning model, a resource that can operate for six hours during an event benefits the system more than a resource with a four-hour event limit.[15/] By extending the maximum BIP event duration to six hours, the BIP will be positioned to more effectively address system outages when they are most likely to occur.

PG&E also plans to pursue tariff updates to include credit and collection provisions, along with collateral requirements.

2. **SmartAC™ Program.** The SmartAC™ program is an air conditioning direct load control program which offers enrollment to residential customers. PG&E plans to continue the SmartAC™ program that was approved in D.16-06-029 for 2018-2022 and will continue

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14/ D.16-06-029.

15/ D.16-06-007, OP 4, adopted the Renewable Energy Capacity Planning (RECAP) model as the method for hourly time-allocation of avoided generation capacity costs to be used across all Commission proceedings. For DR cost effectiveness, it informs the A Factor.

implementation of measures to improve customer experience, and economic efficiency and reliability to support market integration. PG&E will continue to assess the success of new processes for cost-effectiveness, and may make modifications to ensure efficiency.

3. **Capacity Bidding Program.** CBP is a DR program for customers on a commercial, industrial, or agricultural electric rate schedule to enroll through a third-party aggregator or through self-aggregation. To better serve the grid as a supply side resource, PG&E proposes three changes to CBP. First, it will eliminate the Day-Of option, which is a necessary program enhancement because the notification time does not match with the day-ahead energy market requirements of the CAISO. Second, PG&E will eliminate the three event duration products (from 1-4 hours, 2-6 hours, and 4-8 hours) in favor of a new, single event duration of 1-6 hours. Consolidating CBP customers under a single event duration will more easily enable PG&E to meet the 100 kW minimum size by subLAP and LSE needed to create a PDR because all CBP customers will be consolidated under a single event duration. Finally, CBP hours will be shifted from 11:00 a.m.-7:00 p.m. to 1:00 p.m.-9:00 p.m. to reflect the higher value of these revised hours due to the trend of system peak loads shifting to later in the day and evening.

To expand participation options for a broader array of customers' and aggregators' choices, CBP will have three options for participation, based on the customer's and aggregator's preference for the amount of control over hours of participation and/or price at which the program is bid into the CAISO market. PG&E will also open all CBP options to residential aggregators, which PG&E hopes will result in more DR participation in the residential market.

4. Load Modifying Resources. While PG&E is on track to integrate its DR programs by 2018 (May 2017 for BIP), PG&E proposes to continue five Load Modifying Resource DR programs. PG&E will continue its Critical Peak Pricing (CPP) programs, i.e. SmartRate™ and Peak Day Pricing (PDP). Though funding for these programs are approved in other rate setting proceedings,[16/] funding to cover the costs of measure and evaluation are

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16/ The cost of SmartRate™ and PDP administration is normally included in the GRC.

currently included in the proposed DR budget but will transition to the GRC starting in 2020. The PDP and SmartRate™ programs will operate from June 1 through September 30 with a frequency range from 9 to 15 events each calendar year.

Next, the Permanent Load Shift (PLS) program provides incentives for customers to adopt qualifying thermal energy storage technologies to shift cooling load and help reduce system peak by shifting electricity use from higher cost on-peak hours to lower cost off peak hours. In spite of a low customer participation rate, PG&E proposes to continue PLS program incentives and benefits with no change to the program's features. However, PG&E proposes a reduction in annual budget to reflect lower historical enrollment since the program was approved in 2013.

Similarly, PG&E proposes no changes to its Optional Binding Mandatory Curtailment Program (OBMC), which was created as an alternative to a rotating outage for participating customers. In compliance with D.09-08-027, the program is capped at 10.9 MW. The OBMC is fully subscribed and there is a wait list for customers who apply for this program.

Finally, PG&E proposes to continue the Scheduled Load Reduction Program (SLRP) for industrial customers as required by Public Utilities Code Section 740.10, despite the lack of participation. The SLRP has no current customers, and has had only one customer since its inception in 2001.

5. **Emergency Demand Response Cap**. The IOUs are subject to a statewide limit on the amount of emergency DR that they can count for RA credit.[17/] The initial cap was set at 3.5% of the CAISO historical system peak load of 50,270 and was reduced incrementally each year by 0.5%. Since the cap reached 2% (1,005 MW) in 2014, it has remained fixed. PG&E's share of the statewide cap is 32.8% which translates to 330 MW.[18/]

PG&E reached its cap in late 2016 and now has a waiting list for prospective BIP customers that are waiting for headroom to become available. PG&E currently assumes that

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17/ D.10-06-034, Appendix A, p.2-3.

18/ *Id.*, Appendix A, p.9.

Reliability Demand Response Resources (RDRR) procured through the 2017 DRAM counts against the cap. However, once the 2017 DRAM RDRR contracts expire, PG&E will give those BIP customers that are on the waiting list the right of first refusal. Any remaining room would then be available for the next DRAM solicitation.

Based on PG&E's understanding of the settlement approved by D.10-06-034, if any of the DRAM RDRR resources bid into the CAISO day-ahead market in a manner consistent with the CAISO's availability assessment hours, they should be considered economic and not emergency resources, and therefore not subject to the cap.[19/] However, PG&E does not have the visibility of DRAM sellers' bidding behavior to know whether a DRAM RDRR is bidding in such a way as to be exempt from the cap, so there is no way for PG&E to account for this in how it counts DRAM RDRR against the cap.

6. **Dual Participation**. Commission rules allow, in some instances, for customers to simultaneously participate in two DR programs. Customers may participate in one capacity-based program (i.e. a program with only a capacity payment incentive) and one energy-based program (i.e. a program with only an energy payment incentive). In addition, if one of the capacity-based or energy-based programs has day-ahead notification then the other must be day-of. Also, under PG&E Electric Rule 24, no customer can simultaneously participate in the DRAM, which depends on CAISO registration, and an IOU DR program.[20/]

If the capacity-based program and the energy-based program are dispatched during overlapping hours, the customer will receive payment from PG&E only for the capacity program during the overlapping hours.

7. Prohibited Resources. The Guidance Decision prohibits the following technologies from being used for load reduction during DR events: distributed generation technologies using diesel, natural gas, gasoline, propane, or liquefied petroleum gas, in topping

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19/ CAISO rules allow RDRRs to bid into the day-ahead market in addition to being available for day-of dispatch consistent with CAISO Operating Procedure 4420.

20/ PG&E Electric Rule 24 (Section C-2-d).

cycle combined heat and power (CHP) or non-CHP configuration.[21/] The following technologies are exempt from the prohibition: pressure reduction turbines and waste-heat-to-power bottoming cycle CHP, as well as storage and storage coupled with renewable generation that meet the relevant greenhouse gas emissions standards adopted for the Self Generation Incentive Program.[22/]

The Guidance Decision also specifies that the prohibition applies to all PG&E DR programs with the exception of Peak Day Pricing, SmartRate™, SmartAC™, OBMC, and SLRP.[23/] To comply with the Commission's policy on prohibited resources, PG&E submitted AL 4991-E on January 3, 2017 to add enforcement provisions to the tariffs of the programs that are subject to the prohibition. Pending Commission approval of the residential CBP, PG&E will include the appropriate language in the associated tariff. It will also be necessary to revise the 2018-2019 DRAM Purchase Agreement to reflect the updated prohibition and verification regime.

In addition to revising its program tariffs and DRAM contracts, the IOUs will retain a consultant to develop recommendations on how best to design an audit verification plan for non-residential DR participants.

8. DR Enabling Technology. PG&E's Automated Demand Response (ADR) program provides incentives to customers to help offset the purchase and installation costs of BTM DER technologies (e.g. energy efficient devices, energy storage, EVs and EV charging stations) that are ADR-enabled, i.e. that are capable of receiving ADR signals for DR events. While PG&E will maintain the core of the current ADR program design, PG&E proposes to implement or evaluate program enhancements, including: (1) promoting programs that provide rebates for the customer to adopt BTM DER technologies (for e.g. batteries or EV) that are ADR-enabled, (2) pilot a new incentive structure based on the incremental cost of the ADR

21/ D.16-09-056, pp. 94-97 (OP 1-5).
22/ *Id.,* pp. 94-95 (OP 3).
23/ *Id.,* p. 95 (OP 3).

communication technology embedded in the end-use device rather than on $/kW DR potential of the end-use device, and (3) investigate the feasibility of midstream and upstream incentives, and their ability to drive adoption of ADR-enabled BTM end-uses more efficiently than current downstream incentives.

PG&E's Demand Response Emerging Technologies (DRET) program enables the assessment of new technologies and applications—such as "smart" devices behind customers' meters, design tools, channels, or new program features—that have the potential to enhance customers' ability to better perform on DR, and facilitate DR integration into the CAISO markets. PG&E proposes to use the DRET program to explore a potential gap in the delivery of DR for vendors of BTM technology with the potential to provide DR resources but may not have the desire or capacity to change their business model to become an aggregator or DR provider themselves. PG&E also proposes to use DRET to study possible incentives to midstream and upstream market actors to adopt automated technologies that use standard open communication protocols, and to consider methodologies to determine deemed ADR incentives and how best to determine the incremental communication cost for different types of DR enabling technologies.

9. Pilots. PG&E proposes continuing two pilots. The Supply Side II DR Pilot (SSP II) is intended to augment the DRP and IDER proceedings by investigating customer interest in and the feasibility of utilizing DR resources that are integrated in the wholesale energy market to also address local distribution needs. This pilot would continue beyond 2017, with a proposed reassessment as part of the mid-cycle review to investigate ways to operationalize the integration of wholesale DR resources with distribution operations. One objective of the SSP II DR pilot is to determine whether customers are willing to be dispatched frequently enough and over the range of hours necessary to meet both local distribution needs and the Commission and CAISO requirements for DR RA resources.

The main goal of the Excess Supply DR Pilot is to explore how customers can help mitigate situations of excess wind and solar power supply, by shifting their load consumption to align with periods of excess supply. While progress has been made on the pilot's objectives, and it is anticipated that additional results will be available by the end of 2017, not all of the objectives will be fully addressed by the end of 2017. As a result, PG&E proposes continuing the pilot beyond 2017, with a reassessment as part of the mid-cycle review. One objective of the Excess Supply DR Pilot is to assess what triggers, other than CAISO energy market pricing, can be used to call events as early as possible to allow a sufficient amount of time to notify participants of an event.

10. **Marketing, Education, Outreach, and Training**. PG&E plans to continue its test-and-learn approach for expanding education, and providing effective notifications to customers about changes in DR programs. The primary goal for DR-related marketing and outreach will be the "Education and Retention" of customers. The Education and Retention goal will seek to increase customer awareness and trust in the benefits of DR program participation. PG&E's testimony details the strategies to be employed to achieve its goals, including integration with outreach efforts underway in related Commission proceedings, the electronic and non-electronic communications channels planned to reach customers, and a metrics and evaluation plan to monitor the effectiveness of the marketing campaigns.

D. Budgets, Program Flexibility, Cost Recovery, and Cost-Effectiveness Evaluation.

1. Proposed 2018-2022 Budget

PG&E requests $349 million for the 2018-2022 funding cycle, or approximately $70 million each year. This request is approximately $9.7 million less per year than was authorized in D.16-06-029 for 2017. This reduction is due to the closure of programs, completion of information technology systems work required to integrate PG&E DR programs into the CAISO, and reductions in marketing expenses. PG&E's 2018-2022 DR programs funding request is summarized below and in Table 6-1 of PG&E's Opening Testimony:

TABLE 2
PACIFIC GAS AND ELECTRIC COMPANY
SUMMARY OF UTILITY DEMAND RESPONSE PROGRAMS AND BUDGETS FOR 2018-2022
PROGRAM CATEGORY BY YEAR EXPENSES
(THOUSANDS OF DOLLARS)

Line Item	Chp.	Funding Categories	2018	2019	2020	2021	2022	2018-2022 Total
1		**Category 1: Reliability Programs**						
2	2B	Base Interruptible Program (BIP)	$32,315	$32,332	$32,349	$32,367	$32,386	$161,748
3	2E	OMBC/SLRP	$12	$12	$12	$13	$13	$62
4		***Category 1 Total***	***$32,326***	***$32,344***	***$32,362***	***$32,380***	***$32,399***	***$161,811***
5		**Category 2 - Price-Responsive Programs**						
6		DBP	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	2D	CBP	$4,057	$4,077	$4,098	$4,119	$4,141	$20,492
8	2C	Smart AC™	$6,557	$6,304	$6,366	$6,314	$6,389	$31,930
9		***Category 2 Total***	***$10,614***	***$10,381***	***$10,464***	***$10,433***	***$10,530***	***$52,422***
10		**Category 3 - DR Provider/Aggregator Managed Programs**						
11		AMP	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]	$ [redacted]
12		***Category 3 Total***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
13		**Category 4 - Emerging & Enabling Technologies**						
14	2I	AutoDR	$4,000	$4,038	$4,077	$4,118	$4,159	$20,392
15	2I	DR Emerging Technology	$1,375	$1,405	$1,436	$1,467	$1,500	$7,184
16		***Category 4 Total***	***$5,375***	***$5,444***	***$5,513***	***$5,585***	***$5,658***	***$27,576***
17		**Category 5 – Pilots**						
18	2J	Supply Side DR Pilot	$2,079	$2,106	$2,134	$2,162	$2,191	$10,673
19	2J	Excess Supply DR Pilot	$595	$603	$611	$619	$627	$3,054
20		***Category 5 Total***	***$2,674***	***$2,709***	***$2,744***	***$2,781***	***$2,818***	***$13,727***
21		**Category 6 - Evaluation, Measurement, and Verification**						
22	5	DRMEC	$3,225	$3,246	$2,118	$2,120	$2,123	$12,832
23		DR Research	$0	$0	$0	$0	$0	$0
24		***Category 6 Total***	***$3,225***	***$3,246***	***$2,118***	***$2,120***	***$2,123***	***$12,832***

25		**Category 7 - Marketing, Education, and Outreach**						
26	2K	DR Core Marketing & Outreach	$2,483	$2,538	$2,595	$2,652	$2,711	$12,980
27	2K	Education and Training	$250	$258	$266	$275	$284	$1,333
28		***Category 7 Total***	***$2,733***	***$2,796***	***$2,861***	***$2,927***	***$2,995***	***$14,313***
29		**Category 8 - DR System Support Activities**						
30	4	Support for Retail & Customer-Facing Activities	$4,227	$3,779	$3,864	$3,951	$4,041	$19,862
31	4	Support for Market Activities	$3,784	$2,317	$2,384	$2,453	$2,525	$13,464
32	4	Rule 24 O&M	$2,438	$2,509	$2,581	$2,657	$2,734	$12,919
33	6	DR Integration Policy & Planning	$1,570	$1,617	$1,665	$1,715	$1,766	$8,332
34		***Category 8 Total***	***$12,019***	***$10,222***	***$10,495***	***$10,776***	***$11,065***	***$54,577***
35		**Category 9 - Integrated Programs and Activities (Incl. TA/TI)**						
36		Technology Incentives	$0	$0	$0	$0	$0	$0
37		***Category 9 Total***	***$0***	***$0***	***$0***	***$0***	***$0***	***$0***
38		**Category 10 - Special Projects**						
39	2E	Permanent Load Shifting (PLS)	$2,250	$2,261	$2,271	$2,283	$2,294	$11,359
40		***Category 10 Total***	***$2,250***	***$2,261***	***$2,271***	***$2,283***	***$2,294***	***$11,359***
41		**TOTAL DR Portfolio**	**$71,217**	**$69,402**	**$68,828**	**$69,285**	**$69,883**	**$348,615**

2. Fund Shifting Flexibility

PG&E requests the Commission continue existing fund-shifting rules approved in D.12-04-045 to provide PG&E the flexibility to shift a portion of the approved budget between programs within the same budget category, and to respond effectively to any unforeseen changes or developments and efficiently use funds for programs with the highest value and/or greatest participation.[24/] The fund shifting rules also provide the flexibility to reallocate up to 50 percent of authorized budget funds between programs within each budget category without prior Commission authorization.[25/] PG&E proposes to retain the existing ability to carry unspent funds within each budget category from one year into subsequent years.

24/ D. 12-04-045, pp. 25-28.
25/ D. 12-04-045, p. 27.

3. Cost Recovery Proposal

PG&E proposes to include in distribution rates the forecast revenue requirement approved in this proceeding beginning in January 1, 2018. Thus, the distribution rate will recover revenues related to the DR program and activities which will be recorded to the Distribution Revenue Adjustment Mechanism. PG&E requests authority to record the actual revenue requirements associated with the DR programs and activities in the, Demand Response Expenditures Balancing Account (DREBA). PG&E currently uses DREBA to track its authorized revenue requirements and actual costs associated with the DR programs and activities, and proposes to continue doing so. On an annual basis, the balance in the DREBA would be transferred to the Distribution Revenue Adjustment Mechanism as part of the Annual True-Up (AET) process at the end of the year for rates effective January 1 of the following year.

The DREBA balance transfer to the Distribution Revenue Adjustment Mechanism would result in either a net over-collection or a net under-collection when compared with the revenues collected for the DR program in distribution rates recorded to the Distribution Revenue Adjustment Mechanism. The over-collection or under-collection would then be amortized in rates in the following year's authorized revenue requirement. The transfer of the DREBA balance to the Distribution Revenue Adjustment Mechanism for collection in rates would be consolidated with other rate changes in the annual AET Advice Letter, filed in August with a supplemental update in December.

Costs for the 2018-2019 DRAM pilot have already been approved in D.16-06-029, and are not included in this Application. Costs for DRAM after 2019 (i.e. 2020-2022) are not yet known, and await the Commission's decision on transitioning DRAM from a pilot to its next stage. Therefore, PG&E requests Commission direction to address DRAM costs after 2019 in the DRAM advice letter and resolution process ordered in the Guidance Decision.

4. Cost-Effectiveness Evaluation

For its Cost-Effectiveness (CE) evaluation included in this Application, PG&E performed CE analyses for each DR program individually and for its total portfolio using the 2016 Demand Response Cost-Effectiveness Protocols (2016 Protocols).[26/] PG&E also relied upon the Guidance Decision, D.15-11-042 (DR CE Decision) as well as previous guidance from the Commission and Energy Division.[27/] Table 3[28/] presents the Benefit-Cost (B/C) ratios using the Total Resource Cost (TRC) test for PG&E's DR programs and total portfolio:

TABLE 3
2018-2022 DR PROGRAMS
BENEFIT/COST RATIO USING TRC TEST
1-IN-2 YEAR WEATHER CONDITIONS, PORTFOLIO VIEW
INCLUDING ADR COSTS FOR CAPACITY BIDDING PROGRAM (CBP)

Line No.	DR Program	TRC Test Benefit-Cost Ratio (Including ADR costs for CBP)	TRC Test Benefit-Cost Ratio (Excluding ADR costs for CBP)
1	Base Interruptible Program (BIP)	1.6	1.6
2	Capacity Bidding Program (CBP)	0.9	1.0
3	SmartAC™	1.3	1.3
4	Permanent Load Shifting (PLS)	0.7	0.7
5	Total DR Portfolio	1.2	1.3

The TRC of CBP is comparatively lower relative to BIP. This is partially due to the directly allocated costs coming from the Automated Demand Response (ADR) program for

26/ Resolution E-4788, July 14, 2016, and its Appendix A include the final adopted 2016 Demand Response Cost-Effectiveness Protocols and D.15-11-042, *Decision Addressing the Valuation of Load Modifying Demand Response and Demand Response Cost-Effectiveness Protocols*, November 31, 2015. Pursuant to D.10-12-024 and affirmed in D.15-11-042, Critical Peak Pricing (CPP) rates, i.e., Peak Day Pricing and SmartRate™, and pilot programs are not included in the CE analysis.

27/ The additional guidance PG&E relied upon in contained at Table 7-4 of PG&E's Opening Testimony

28/ All CE analyses are presented in PG&E's Opening Testimony, Chapter 7.

non-residential CBP customers. If this ADR cost is not allocated to CBP, its TRC increases to 1.0.

Table 4 shows B/C ratios by the other three CE tests using the Commission's Standard Practice Manual (SPM)[29/] for each DR program and total portfolio (including ADR costs for CBP).

TABLE 4
2018-2022 DR PROGRAMS
1-IN-2 YEAR WEATHER CONDITIONS, PORTFOLIO VIEW, INCLUDING ADR COSTS FOR CBP

Line No.	DR Program	Ratepayer Impact Measure Test	Program Administrator Test	Participant Cost Test
1	BIP	1.3	1.3	1.3
2	CBP	0.8	0.8	1.3
3	SmartAC	1.2	1.2	2.9
4	PLS	0.5	1.6	1.5
5	Total DR Portfolio	1.0	1.1	1.4

Finally, Table 5 presents the benefits, costs and net benefits from each program and the portfolio. A negative net benefit represents the dollar amount that would have to be removed to result in a TRC B/C ratio of exactly 1.0.

TABLE 5
2018-2022 DR PROGRAMS
NPV TRC TEST BENEFITS AND COSTS
1-IN-2 YEAR WEATHER CONDITIONS, PORTFOLIO VIEW, INCLUDING ADR COSTS FOR CBP
(MILLIONS OF DOLLARS)

Line No.	DR Program	Benefits	Costs	Net Benefits
1	BIP	$206.0	$127.6	$78.4
2	CBP	$24.0	$27.6	$(3.6)
3	SmartAC	$45.9	$35.3	$10.6
4	PLS	$18.7	$25.1	$(6.4)
5	Miscellaneous	–	$20.4	$(20.4)
6	Total DR Portfolio	$294.6	$236.0	$58.6

29/ The CPUC's "California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects" (October 2001).

E. Overview of PG&E's Prepared Written Testimony

PG&E's prepared written testimony accompanying this Application consists of one exhibit containing the following chapters:

Chapter	Title
1	Policy and Summary of Proposals
2	Proposed Improvements to Existing PG&E-Implemented Programs and Pilots
3	Enablement of Third-Party Supply Resource Demand Response
4	Demand Response Operations
5	Load Impacts, Measurement and Evaluation
6	Budget and Budget Flexibility
7	Cost-Effectiveness Evaluation
8	Cost Recovery and Revenue Requirements

II. REVENUE REQUIREMENT AND RATEMAKING PROPOSALS

The revenue requirements associated with the expenditures for DR programs and activities that PG&E seeks to recover in rates from all distribution service customers is $352.8 million during 2018-2022 program period. The total expense budgets as shown in line 1 of Table 8-1 of PG&E's Opening Testimony are converted to the total revenue requirements, shown in *Line* 4, by grossing up or adding Franchise Fees and Uncollectibles (FF&U) and Benefits Burden to the expense budgets.[30/]

30/ The calculated FF&U factor and Benefits Burden amounts are based on PG&E's 2014 GRC Settlement approved by the Commission, D.14-08-032. The amount specified in Line 2, $2.438 million and Line 3, which has been calculated to add FF&U Factor, is a placeholder applied from GRC 2014 Decision 14-08-032. PG&E will adjust the amount for 2018 and beyond in the subsequent AET filing after the Commission's decision on PG&E's pending 2017 GRC Application.

TABLE 6
PACIFIC GAS AND ELECTRIC COMPANY
DEMAND RESPONSE 2018-2022 PROPOSED REVENUE REQUIREMENTS
(THOUSANDS OF DOLLARS)

	2018	2019	2020	2021	2022	Total
Program Expense Budget	$71,217	$69,402	$68,828	$69,285	$69,883	$348,615
FF&U Factor	0.011885	0.011885	0.011885	0.011885	0.011885	
Program Expense Revenue Requirement (Line 1 x FF&U) factor	$846	$825	$818	$823	$831	
Total Revenue Requirements (Line 1 + Line 3)	$72,064	$70,227	$69,646	$70,109	$70,713	$352,758

III. INFORMATION REQUIRED BY THE COMMISSION'S RULES OF PRACTICE AND PROCEDURE AND OTHER REQUIREMENTS

PG&E provides the following information in compliance with the Commission's Rules of Practice and Procedure.

A. Statutory and Other Authority (Rule 2.1)

PG&E's Application is filed pursuant to D.16-09-056, OP 6, and Rules 2.1-2.3, 3.2, and 7.1 of the Commission's Rules of Practice and Procedure. PG&E also submits this Application pursuant to Sections 451, 454, 701, 728, 729, 740.4 and 795 of the Public Utilities Code, and prior decisions and orders of the Commission.

B. Legal Name and Principal Place of Business (Rule 2.1(a))

The legal name of the Applicant is Pacific Gas and Electric Company. PG&E is a corporation organized under the State of California. PG&E's principal place of business is 77 Beale Street, San Francisco, California 94105.

C. Correspondence and Communications (Rule 2.1(b))

All correspondence, communications, and service of papers regarding this Application should be directed to PG&E as follows:

Darren P. Roach
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Pacific Gas and Electric Company
P.O. Box 7442
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D. Categorization, Hearings, and Issues to be Considered (Rules 2.1(c) and 7.1)

1. Proposed Category

PG&E proposes that this Application be categorized as a ratesetting proceeding.

2. Need for Evidentiary Hearings

PG&E submits that hearings are unnecessary to address this Application, as PG&E's proposals herein and in its Opening Testimony constitute a sufficient record for the Commission to rule on PG&E's proposals. To the extent hearings are deemed necessary, PG&E proposes a procedural schedule in subsection 4 below that would allow this Application to be resolved no later than November 30, 2017.

3. Issues to be Considered

The following issues should be considered in this proceeding:

(a) PG&E's DR program and pilot recommendations for 2018-2022;

(b) PG&E's proposed budget for implementation of these programs;

(c) PG&E's proposals regarding program budget categories and budget flexibility;

(d) PG&E's proposals to support the operations of the 2018-2022 DR portfolio;

(e) PG&E's load impacts, measurement and evaluation proposals;

(f) PG&E's cost effectiveness evaluations;

(g) PG&E's cost and rate recovery recommendations;

(h) PG&E's recommendation that DRAM costs after 2019 be addressed in the DRAM advice letter and resolution process ordered in the Guidance Decision; and

(i) Other issues the Commission finds just and reasonable in support of a timely resolution of this Application.

4. Proposed Schedule

PG&E is ready to proceed with its showing in support of this Application immediately and has concurrently served its Opening Written Testimony and Appendices. If hearings are required, PG&E proposes the following schedule in order to obtain a final decision on the Application by November 30, 2017.

ACTIVITY	PROPOSED SCHEDULE
Applications Filed	January 17, 2017
Protests/Responses to Applications	February 21, 2017
Replies to Protests	March 3, 2017
Prehearing Conference	April 3, 2017
Scoping Memo	April 25, 2017
ORA and Intervenor testimony	May 31, 2017
Rebuttal Testimony	June 28, 2017
Hearings	July 24-25, 2017
Discovery Cut-Off	August 4, 2017

Concurrent Opening Briefs	August 25, 2017
Concurrent Reply Briefs	September 15, 2017
Commission Proposed Decision	October 20, 2017
Comments on Proposed Decision	November 9, 2017
Reply Comments on Proposed Decision	November 14, 2017
Commission issues Final Decision	November 30, 2017

E. Articles of Incorporation (Rule 2.2)

PG&E is, and since October 10, 1905, has been an operating public utility corporation organized under California law. It is engaged principally in the business of furnishing electric and gas services in California. A certified copy of PG&E's Restated Articles of Incorporation, effective April 12, 2004, was filed with the Commission on May 3, 2004 with PG&E's Application 04-05-005. These articles are incorporated herein by reference pursuant to Rule 2.2 of the Commission's Rules.

F. Authority to Increase Rates (Rule 3.2)

This Application proposes electric rates to take effect after the currently approved rates are scheduled to expire on December 31, 2017. The rates proposed by this Application are less than the rates currently in effect. Therefore, PG&E is providing material in this Application that complies with Rule 3.2. This Application is not a general rate increase application, so Rule 3.2(a) applies except for subsections (4), (7), (8), and (9).

G. Balance Sheet and Income Statement (Rule 3.2(a)(1))

PG&E presents the most recent balance sheet and income statement for the period ending September 30, 2016 at Exhibit 1 of this Application.

H. Statement of Presently Effective Rates (Rule 3.2(a)(2))

PG&E presents its presently effective electric rates at Exhibit 2 of this Application.

I. Statement of Proposed Changes and Results of Operations at Proposed Rates (Rule 3.2(a)(3))

PG&E proposes changes in customer electric rates as compared to presently effective rates. In 2018, the year of the largest revenue requirement proposed, the bill for a typical residential Non-CARE customer using 500 kWh per month would decrease 0.1% percent from $99.13 to $99.04.

Approval of this Application would not increase electric rates by more than one percent compared to existing rates, therefore a statement setting forth PG&E's proposed increases or changes to electric rates by customer class is not needed.

J. General Description of PG&E's Electric and Gas Department Plant (Rule 3.2(a)(4))

Because this submittal is not a general rate application, this requirement is not applicable.

K. Summary of Earnings (Rule 3.2(a)(5) and Rule 3.2(a)(6))

A summary of recorded year 2015 revenues, expenses, rate cases and rate of return for PG&E's Electric Department was filed with the Commission on October 31, 2016, in Application 16-10-019 and is incorporated by reference.

L. Statement of Election of Method of Computing Depreciation Deduction for Federal Income Tax (Rule 3.2(a)(7))

Because this submittal is not a general rate application, this requirement is not applicable.

M. Most Recent Proxy Statement - Rule 3.2(a)(8)

Because this submittal is not a general rate application, this requirement is not applicable.

N. Type of Rate Change Requested (Rule 3.2(a)(10))

The rate changes sought in this Application reflect and pass through to customers increased costs to the corporation for the services furnished by it.

O. Notice to Governmental Entities (Rule 3.2(b))

PG&E presents a list of governmental entities, including the State of California and cities and counties served by PG&E, at Exhibit 3, to whom PG&E will mail a notice stating in general terms the proposed rate changes within 20 days of filing this Application.

P. Publication (Rule 3.2(c))

PG&E will publish in newspapers of general circulation in each county in its service territory a notice of filing within twenty days after filing this Application.

Q. Notice to Customers (Rule 3.2(d))

PG&E is serving this Application and Opening Testimony on the services list in R. 13-09-011, and A. 11-03-001. PG&E will include notices with the regular bills mailed and emailed to all customers affected by the proposed changes within 45 days of filing this Application.

R. Safety (Rule 2.1(c))

In D.16-01-017, OP 1, the Commission adopted an amendment to Rule 2.1(c) requiring Applications to clearly state "relevant safety considerations." This Application identifies two safety issues. First, by approving this Application for the continued operation of PG&E's programs, and costs associated with their operation, the Commission will ensure PG&E has sufficient funds and authority to continue to operate its programs in a safe and reliable manner. Second, this Application references contracts with DRAM and third-party providers of DR resources. PG&E's contracts with these resources will address safety and will provide criteria and requirements for providers to safely operate in compliance with legal and regulatory requirements.

IV. REQUESTED RELIEF

WHEREFORE, Pacific Gas and Electric Company respectfully requests that the Commission issue a decision and order no later than November 2017 that:

A. Adopts PG&E's DR program and pilot recommendations for 2018-2022 program cycle;

B. Approves PG&E's proposed budget for implementation of these programs and pilots;

C. Approves PG&E's proposals regarding program budget categories and budget flexibility;

D. Approves PG&E's proposals to support the operations of the 2018-2022 DR portfolio;
E. Approves PG&E's load impacts, measurement and evaluation proposals;
F. Approves PG&E's cost effectiveness evaluations;
G. Adopts PG&E's recommendation regarding cost and rate recovery;
H. Adopts PG&E's recommendation that DRAM costs after 2019 be addressed in the DRAM advice letter and resolution process ordered in the Guidance Decision; and
I. Grants other relief as the Commission finds just and reasonable.

Executed at San Francisco, California, this 17th day of January 2017.

Respectfully Submitted,

MARY A. GANDESBERY
SHIRLEY A. WOO
DARREN P. ROACH

BY: *[/s/ Darren P. Roach]*
DARREN P. ROACH

PACIFIC GAS AND ELECTRIC COMPANY
77 Beale Street, B30A
San Francisco, CA 94105
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ATTORNEYS FOR
PACIFIC GAS AND ELECTRIC COMPANY

Dated: January 17, 2017

VERIFICATION

I, Aaron J. Johnson, say:

I am an officer of Pacific Gas and Electric Company, a corporation, and am authorized pursuant to 2.1 and Rule 1.1 of the California Public Utilities Commission's Rules of Practice and Procedure to make this Verification for and on behalf of said corporation, and I make this verification for that reason. I have read the foregoing Application and I am informed and believe that the matters therein concerning Pacific Gas and Electric Company are true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed at San Francisco, California, this 11th day of January 2017.

/s/ Aaron J. Johnson
AARON J. JOHNSON

Vice President
Customer Energy Solutions
Pacific Gas and Electric Company

EXHIBIT 1

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	**2016**	**2015**	**2016**	**2015**
Operating Revenues				
Electric	$ 3,993	$ 3,868	$ 10,590	$ 10,344
Natural gas	816	682	2,363	2,322
Total operating revenues	**4,809**	**4,550**	**12,953**	**12,666**
Operating Expenses				
Cost of electricity	1,613	1,681	3,719	3,958
Cost of natural gas	80	50	377	442
Operating and maintenance	1,782	1,622	5,630	5,028
Depreciation, amortization, and decommissioning	694	653	2,090	1,935
Total operating expenses	**4,169**	**4,006**	**11,816**	**11,363**
Operating Income	**640**	**544**	**1,137**	**1,303**
Interest income	8	2	16	6
Interest expense	(209)	(191)	(614)	(567)
Other income, net	23	22	68	68
Income Before Income Taxes	**462**	**377**	**607**	**810**
Income tax provision (benefit)	73	72	(99)	95
Net Income	**389**	**305**	**706**	**715**
Preferred stock dividend requirement	3	3	10	10
Income Available for Common Stock	**$ 386**	**$ 302**	**$ 696**	**$ 705**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions)	September 30, 2016	December 31, 2015
ASSETS		
Current Assets		
Cash and cash equivalents	$ 68	$ 59
Restricted cash	168	234
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $53 and $54 at respective dates)	1,233	1,106
Accrued unbilled revenue	956	855
Regulatory balancing accounts	1,475	1,760
Other	473	284
Regulatory assets	370	517
Inventories:		
Gas stored underground and fuel oil	134	126
Materials and supplies	343	313
Income taxes receivable	194	130
Other	306	338
Total current assets	**5,720**	**5,722**
Property, Plant, and Equipment		
Electric	51,532	48,532
Gas	17,384	16,749
Construction work in progress	2,117	2,059
Total property, plant, and equipment	**71,033**	**67,340**
Accumulated depreciation	(21,603)	(20,617)
Net property, plant, and equipment	**49,430**	**46,723**
Other Noncurrent Assets		
Regulatory assets	7,534	7,029
Nuclear decommissioning trusts	2,597	2,470
Income taxes receivable	70	135
Other	1,066	958
Total other noncurrent assets	**11,267**	**10,592**
TOTAL ASSETS	**$ 66,417**	**$ 63,037**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions, except share amounts)	**September 30, 2016**	**December 31, 2015**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 981	$ 1,019
Long-term debt, classified as current	160	160
Accounts payable:		
Trade creditors	1,370	1,414
Regulatory balancing accounts	764	715
Other	765	418
Disputed claims and customer refunds	233	454
Interest payable	144	203
Other	1,681	1,750
Total current liabilities	**6,098**	**6,133**
Noncurrent Liabilities		
Long-term debt	16,179	15,577
Regulatory liabilities	6,613	6,321
Pension and other postretirement benefits	2,540	2,534
Asset retirement obligations	4,672	3,643
Deferred income taxes	10,135	9,487
Other	2,350	2,282
Total noncurrent liabilities	**42,489**	**39,844**
Commitments and Contingencies (Note 9)		
Shareholders' Equity		
Preferred stock	258	258
Common stock, $5 par value, authorized 800,000,000 shares; 264,374,809 shares outstanding at respective dates	1,322	1,322
Additional paid-in capital	7,955	7,215
Reinvested earnings	8,291	8,262
Accumulated other comprehensive income	4	3
Total shareholders' equity	**17,830**	**17,060**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**$ 66,417**	**$ 63,037**

See accompanying Notes to the Condensed Consolidated Financial Statements.

EXHIBIT 2

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF JANUARY 1, 2017

RESIDENTIAL RATES

LINE NO.		1/1/17 RATES SUMMER	1/1/17 RATES WINTER	LINE NO.
1	SCHEDULE E-1			1
2	MINIMUM BILL ($/MONTH)	$10.00	$10.00	2
3	ES UNIT DISCOUNT ($/UNIT/MONTH)	$1.54	$1.54	3
4	ET UNIT DISCOUNT ($/UNIT/MONTH)	$5.48	$5.48	4
5	ES/ET MINIMUM RATE LIMITER ($/KWH)	$0.04892	$0.04892	5
6	ENERGY ($/KWH)			6
7	TIER 1	$0.18276	$0.18276	7
8	TIER 2	$0.24175	$0.24175	8
9	TIER 3	$0.24175	$0.24175	9
10	TIER 4	$0.40139	$0.40139	10
11	TIER 5	$0.40139	$0.40139	11
12	SCHEDULE EL-1 (CARE)			12
13	MINIMUM BILL ($/MONTH)	$5.00	$5.00	13
14	ENERGY ($/KWH)			14
15	TIER 1	$0.11975	$0.11975	15
16	TIER 2	$0.14777	$0.14777	16
17	TIER 3	$0.21746	$0.21746	17

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF JANUARY 1, 2017

RESIDENTIAL RATES

LINE NO.		1/1/17 RATES SUMMER	1/1/17 RATES WINTER	LINE NO.
1	SCHEDULE E-6 / EM-TOU			1
2	MINIMUM BILL ($/MONTH)	$10.00	$10.00	2
3	E-6 METER CHARGE ($/MONTH)	$7.70	$7.70	3
4	ON-PEAK ENERGY ($/KWH)			4
5	TIER 1	$0.34230		5
6	TIER 2	$0.40129		6
7	TIER 3	$0.40129		7
8	TIER 4	$0.56003		8
9	TIER 5	$0.56003		9
10	PART-PEAK ENERGY ($/KWH)			10
11	TIER 1	$0.22703	$0.17142	11
12	TIER 2	$0.28602	$0.23041	12
13	TIER 3	$0.28602	$0.23041	13
14	TIER 4	$0.44476	$0.38915	14
15	TIER 5	$0.44476	$0.38915	15
16	OFF-PEAK ENERGY ($/KWH)			16
17	TIER 1	$0.15025	$0.15459	17
18	TIER 2	$0.20925	$0.21358	18
19	TIER 3	$0.20925	$0.21358	19
20	TIER 4	$0.36798	$0.37232	20
21	TIER 5	$0.36798	$0.37232	21
22	SCHEDULE EL-6 / EML-TOU			22
23	MINIMUM BILL ($/MONTH)	$5.00	$5.00	23
24	EL-6 METER CHARGE($/MONTH)	$6.16	$6.16	24
25	ON-PEAK ENERGY ($/KWH)			25
26	TIER 1	$0.23655		26
27	TIER 2	$0.38755		27
28	TIER 3	$0.38755		28
29	PART-PEAK ENERGY ($/KWH)			29
30	TIER 1	$0.15205	$0.11129	30
31	TIER 2	$0.18115	$0.14037	31
32	TIER 3	$0.26449	$0.20513	32
33	OFF-PEAK ENERGY ($/KWH)			33
34	TIER 1	$0.09577	$0.09894	34
35	TIER 2	$0.12487	$0.12803	35
36	TIER 3	$0.18253	$0.18715	36

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF JANUARY 1, 2017

RESIDENTIAL RATES

LINE NO.		1/1/17 RATES SUMMER	1/1/17 RATES WINTER	LINE NO.
43	SCHEDULE EV: RATE A			43
44	MINIMUM BILL ($/MONTH)	$10.00	$10.00	44
45	ON-PEAK ENERGY ($/KWH)	$0.44976	$0.31604	45
46	PART-PEAK ENERGY ($/KWH)	$0.24573	$0.19381	46
47	OFF-PEAK ENERGY ($/KWH)	$0.11813	$0.12091	47
48	SCHEDULE EV: RATE B			48
49	EV-B METER CHARGE ($/MONTH)	$1.50	$1.50	49
50	ON-PEAK ENERGY ($/KWH)	$0.44324	$0.30911	50
51	PART-PEAK ENERGY ($/KWH)	$0.24247	$0.19034	51
52	OFF-PEAK ENERGY ($/KWH)	$0.11766	$0.12041	52

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF JANUARY 1, 2017

SMALL L&P RATES

LINE NO.		1/1/17 RATES SUMMER	1/1/17 RATES WINTER	LINE NO.
1	SCHEDULE A-1			1
2	CUSTOMER CHARGE: SINGLE-PHASE ($/MO.)	$10.00	$10.00	2
3	CUSTOMER CHARGE: POLYPHASE ($/MO.)	$20.00	$20.00	3
4	ENERGY ($/KWH)	$0.24375	$0.18915	4
5	SCHEDULE A-1 TOU			5
6	CUSTOMER CHARGE: SINGLE-PHASE ($/MO.)	$10.00	$10.00	6
7	CUSTOMER CHARGE: POLYPHASE ($/MO.)	$20.00	$20.00	7
8	ENERGY ($/KWH)			8
9	ON-PEAK	$0.25943		9
10	PART-PEAK	$0.23578	$0.21692	10
11	OFF-PEAK ENERGY	$0.20842	$0.19601	11
12	SCHEDULE A-6			12
13	CUSTOMER CHARGE: SINGLE-PHASE ($/MO.)	$10.00	$10.00	13
14	CUSTOMER CHARGE: POLYPHASE ($/MO.)	$20.00	$20.00	14
15	METER CHARGE ($/MONTH)	$6.12	$6.12	15
16	METER CHARGE - RATE W ($/MONTH)	$1.80	$1.80	16
17	METER CHARGE - RATE X ($/MONTH)	$6.12	$6.12	17
18	ENERGY ($/KWH)			18
19	ON-PEAK	$0.55123		19
20	PART-PEAK	$0.25441	$0.20087	20
21	OFF-PEAK ENERGY	$0.18283	$0.18263	21
22	SCHEDULE A-15			22
23	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	23
24	FACILITY CHARGE ($/MONTH)	$25.00	$25.00	24
25	ENERGY ($/KWH)	$0.24375	$0.18915	25
26	SCHEDULE TC-1			26
27	CUSTOMER CHARGE ($/MONTH)	$10.00	$10.00	27
28	ENERGY ($/KWH)	$0.18077	$0.18077	28

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF JANUARY 1, 2017

MEDIUM L&P RATES

LINE NO.		1/1/17 RATES SUMMER	1/1/17 RATES WINTER	LINE NO.
1	SCHEDULE A-10			1
2	CUSTOMER CHARGE ($/MONTH)	$140.00	$140.00	2
3	MAXIMUM DEMAND CHARGE ($/KW/MO)			3
4	SECONDARY VOLTAGE	$16.78	$9.45	4
5	PRIMARY VOLTAGE	$15.89	$9.75	5
6	TRANSMISSION VOLTAGE	$10.20	$6.83	6
7	ENERGY CHARGE ($/KWH)			7
8	SECONDARY VOLTAGE	$0.16492	$0.16492	8
9	PRIMARY VOLTAGE	$0.15522	$0.12464	9
10	TRANSMISSION VOLTAGE	$0.12222	$0.10368	10
11	SCHEDULE A-10 TOU			11
12	CUSTOMER CHARGE ($/MONTH)	$140.00	$140.00	12
13	MAXIMUM DEMAND CHARGE ($/KW/MO)			13
14	SECONDARY VOLTAGE	$16.78	$9.45	14
15	PRIMARY VOLTAGE	$15.89	$9.75	15
16	TRANSMISSION VOLTAGE	$10.20	$6.83	16
17	ENERGY CHARGE ($/KWH)			17
18	SECONDARY			18
19	ON PEAK	$0.21972		19
20	PARTIAL PEAK	$0.16459	$0.13641	20
21	OFF-PEAK	$0.13652	$0.11935	21
22	PRIMARY			22
23	ON PEAK	$0.20802		23
24	PARTIAL PEAK	$0.15746	$0.13445	24
25	OFF-PEAK	$0.13083	$0.11857	25
26	TRANSMISSION			26
27	ON PEAK	$0.17154		27
28	PARTIAL PEAK	$0.12466	$0.11287	28
29	OFF-PEAK	$0.09936	$0.09830	29

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF JANUARY 1, 2017

E-19 FIRM RATES

LINE NO.		1/1/17 RATES SUMMER	1/1/17 RATES WINTER	LINE NO.
1	SCHEDULE E-19 T FIRM			1
2	CUSTOMER CHARGE > 500 KW ($/MONTH)	$1,800.00	$1,800.00	2
3	CUSTOMER CHARGE < 500 KW ($/MONTH)	$140.00	$140.00	3
4	TOU METER CHARGE - RATES V & X ($/MONTH)	$145.40	$145.40	4
5	TOU METER CHARGE - RATE W ($/MONTH)	$141.08	$141.08	5
6	DEMAND CHARGE ($/KW/MONTH)			6
7	ON-PEAK	$12.42		7
8	PARTIAL PEAK	$3.11	$0.00	8
9	MAXIMUM	$7.65	$7.65	9
10	ENERGY CHARGE ($/KWH)			10
11	ON-PEAK	$0.10765		11
12	PARTIAL-PEAK	$0.09504	$0.09703	12
13	OFF-PEAK	$0.07837	$0.08422	13
14	SCHEDULE E-19 P FIRM			14
15	CUSTOMER CHARGE > 500 KW ($/MONTH)	$1,000.00	$1,000.00	15
16	CUSTOMER CHARGE < 500 KW ($/MONTH)	$140.00	$140.00	16
17	TOU METER CHARGE - RATES V & X ($/MONTH)	$145.40	$145.40	17
18	TOU METER CHARGE - RATE W ($/MONTH)	$141.08	$141.08	18
19	DEMAND CHARGE ($/KW/MONTH)			19
20	ON-PEAK	$16.60		20
21	PARTIAL PEAK	$4.53	$0.15	21
22	MAXIMUM	$12.92	$12.92	22
23	ENERGY CHARGE ($/KWH)			23
24	ON-PEAK	$0.14371		24
25	PARTIAL-PEAK	$0.10533	$0.10015	25
26	OFF-PEAK	$0.08066	$0.08675	26
27	SCHEDULE E-19 S FIRM			27
28	CUSTOMER CHARGE > 500 KW ($/MONTH)	$600.00	$600.00	28
29	CUSTOMER CHARGE < 500 KW ($/MONTH)	$140.00	$140.00	29
30	TOU METER CHARGE - RATES V & X ($/MONTH)	$145.40	$145.40	30
31	TOU METER CHARGE - RATE W ($/MONTH)	$141.08	$141.08	31
32	DEMAND CHARGE ($/KW/MONTH)			32
33	ON-PEAK	$18.64		33
34	PARTIAL PEAK	$5.18	$0.12	34
35	MAXIMUM	$16.08	$16.08	35
36	ENERGY CHARGE ($/KWH)			36
37	ON-PEAK	$0.15384		37
38	PARTIAL-PEAK	$0.11333	$0.10779	38
39	OFF-PEAK	$0.08651	$0.09317	39

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF JANUARY 1, 2017

E-20 FIRM RATES

LINE NO.		1/1/17 RATES SUMMER	1/1/17 RATES WINTER	LINE NO.
1	SCHEDULE E-20 T FIRM			1
2	CUSTOMER CHARGE ($/MONTH)-FIRM	$2,000.00	$2,000.00	2
3	DEMAND CHARGE ($/KW/MONTH)			3
4	ON-PEAK	$15.89		4
5	PARTIAL PEAK	$3.79	$0.00	5
6	MAXIMUM	$6.54	$6.54	6
7	ENERGY CHARGE ($/KWH)			7
8	ON-PEAK	$0.10259		8
9	PARTIAL-PEAK	$0.09036	$0.09228	9
10	OFF-PEAK	$0.07417	$0.07985	10
11	SCHEDULE E-20 P FIRM			11
12	CUSTOMER CHARGE ($/MONTH)	$1,500.00	$1,500.00	12
13	DEMAND CHARGE ($/KW/MONTH)			13
14	ON-PEAK	$19.26		14
15	PARTIAL PEAK	$5.13	$0.12	15
16	MAXIMUM	$13.32	$13.32	16
17	ENERGY CHARGE ($/KWH)			17
18	ON-PEAK	$0.14572		18
19	PARTIAL-PEAK	$0.10510	$0.09975	19
20	OFF-PEAK	$0.08012	$0.08626	20
21	SCHEDULE E-20 S FIRM			21
22	CUSTOMER CHARGE ($/MONTH)	$1,200.00	$1,200.00	22
23	DEMAND CHARGE ($/KW/MONTH)			23
24	ON-PEAK	$1.45		24
25	PARTIAL PEAK	$0.50	$0.01	25
26	MAXIMUM	$15.67	$15.67	26
27	ENERGY CHARGE ($/KWH)			27
28	ON-PEAK	$0.14423		28
29	PARTIAL-PEAK	$0.10738	$0.10203	29
30	OFF-PEAK	$0.08208	$0.08832	30

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF JANUARY 1, 2017

OIL AND GAS EXTRACTION RATES

LINE NO.		1/1/17 RATES SUMMER	1/1/17 RATES WINTER	LINE NO.
1	SCHEDULE E-37			1
2	CUSTOMER CHARGE ($/MONTH)	$36.36	$36.36	2
3	TOU METER CHARGE - RATE W ($/MONTH)	$1.20	$1.20	3
4	TOU METER CHARGE - RATE X ($/MONTH)	$6.00	$6.00	4
5	ON PEAK DEMAND CHARGE ($/KW/MO)	$9.85		5
6	MAXIMUM DEMAND CHARGE ($/KW/MO)			6
7	SECONDARY VOLTAGE	$15.37	$5.95	7
8	PRIMARY VOLTAGE DISCOUNT	$1.71	$0.18	8
9	TRANSMISSION VOLTAGE DISCOUNT	$11.49	$5.12	9
10	ENERGY ($/KWH)			10
11	ON-PEAK	$0.20775		11
12	PART-PEAK		$0.10984	12
13	OFF-PEAK	$0.08974	$0.08143	13

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF JANUARY 1, 2017

STANDBY RATES

LINE NO.		1/1/17 RATES SUMMER	1/1/17 RATES WINTER	LINE NO.
1	SCHEDULE S - TRANSMISSION			1
2	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$1.34	$1.34	2
3	EFFECTIVE RESERVATION CHARGE ($/KW/MO.)	$1.14	$1.14	3
4	ENERGY ($/KWH)			4
5	ON-PEAK	$0.12877		5
6	PART-PEAK	$0.11559	$0.11766	6
7	OFF-PEAK	$0.09816	$0.10428	7
8	SCHEDULE S - PRIMARY			8
9	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$7.03	$7.03	9
10	EFFECTIVE RESERVATION CHARGE ($/KW/MO.)	$5.98	$5.98	10
11	ENERGY ($/KWH)			11
12	ON-PEAK	$0.57894		12
13	PART-PEAK	$0.26944	$0.14187	13
14	OFF-PEAK	$0.11355	$0.12076	14
15	SCHEDULE S - SECONDARY			15
16	CONTRACT CAPACITY CHARGE ($/KW/MO.)	$7.03	$7.03	16
17	EFFECTIVE RESERVATION CHARGE ($/KW/MO.)	$5.98	$5.98	17
18	ENERGY ($/KWH)			18
19	ON-PEAK	$0.57779		19
20	PART-PEAK	$0.26829	$0.14072	20
21	OFF-PEAK	$0.11240	$0.11961	21

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF JANUARY 1, 2017

STANDBY RATES

LINE NO.		1/1/17 RATES SUMMER	1/1/17 RATES WINTER	LINE NO.
1	SCHEDULE S CUSTOMER AND METER CHARGES			1
2	RESIDENTIAL			2
3	CUSTOMER CHARGE ($/MO)	$5.00	$5.00	3
4	TOU METER CHARGE ($/MO)	$3.90	$3.90	4
5	AGRICULTURAL			5
6	CUSTOMER CHARGE ($/MO)	$27.60	$27.60	6
7	TOU METER CHARGE ($/MO)	$6.00	$6.00	7
8	SMALL LIGHT AND POWER (less than or equal to 50 kW)			8
9	SINGLE PHASE CUSTOMER CHARGE ($/MO)	$20.00	$20.00	9
10	POLY PHASE CUSTOMER CHARGE ($/MO)	$30.00	$30.00	10
11	METER CHARGE ($/MO)	$6.12	$6.12	11
12	MEDIUM LIGHT AND POWER (>50 kW, <500 kW)			12
13	CUSTOMER CHARGE ($/MO)	$140.00	$140.00	13
14	METER CHARGE ($/MO)	$5.40	$5.40	14
15	MEDIUM LIGHT AND POWER (>500kW)			15
16	TRANSMISSION CUSTOMER CHARGE ($/MO)	$1,800.00	$1,800.00	16
17	PRIMARY CUSTOMER CHARGE ($/MO)	$1,000.00	$1,000.00	17
18	SECONDARY CUSTOMER CHARGE ($/MO)	$600.00	$600.00	18
19	LARGE LIGHT AND POWER (> 1000 kW)			19
20	TRANSMISSION CUSTOMER CHARGE ($/MO)	$2,000.00	$2,000.00	20
21	PRIMARY CUSTOMER CHARGE ($/MO)	$1,500.00	$1,500.00	21
22	SECONDARY CUSTOMER CHARGE ($/MO)	$1,200.00	$1,200.00	22
23	REDUCED CUSTOMER CHARGES ($/MO)			23
24	SMALL LIGHT AND PWR (< 50 kW)	$7.75	$7.75	24
25	MED LIGHT AND PWR (Res Capacity >75 kW and <500 kW)	$28.91	$28.91	25
26	MED LIGHT AND PWR (Res Capacity > 500 kW and < 1000 kW)	$52.00	$52.00	26

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF JANUARY 1, 2017

AGRICULTURAL RATES

LINE NO.		1/1/17 RATES SUMMER	1/1/17 RATES WINTER	LINE NO.
1	SCHEDULE AG-1A			1
2	CUSTOMER CHARGE ($/MONTH)	$17.47	$17.47	2
3	CONNECTED LOAD CHARGE ($/KW/MONTH)	$7.96	$1.52	3
4	ENERGY CHARGE ($/KWH)	$0.27724	$0.21312	4
5	SCHEDULE AG-RA			5
6	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.47	$17.47	6
7	METER CHARGE - RATE A ($/MONTH)	$6.80	$6.80	7
8	METER CHARGE - RATE D ($/MONTH)	$2.00	$2.00	8
9	CONNECTED LOAD CHARGE ($/KW/MONTH)	$7.08	$1.16	9
10	ENERGY ($/KWH)			10
11	ON-PEAK	$0.52509		11
12	PART-PEAK		$0.18653	12
13	OFF-PEAK	$0.18293	$0.15293	13
14	SCHEDULE AG-VA			14
15	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.47	$17.47	15
16	METER CHARGE - RATE A ($/MONTH)	$6.80	$6.80	16
17	METER CHARGE - RATE D ($/MONTH)	$2.00	$2.00	17
18	CONNECTED LOAD CHARGE ($/KW/MONTH)	$7.10	$1.20	18
19	ENERGY ($/KWH)			19
20	ON-PEAK	$0.49046		20
21	PART-PEAK		$0.18780	21
22	OFF-PEAK	$0.17980	$0.15348	22
23	SCHEDULE AG-4A			23
24	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.47	$17.47	24
25	METER CHARGE - RATE A ($/MONTH)	$6.80	$6.80	25
26	METER CHARGE - RATE D ($/MONTH)	$2.00	$2.00	26
27	CONNECTED LOAD CHARGE ($/KW/MONTH)	$8.12	$1.23	27
28	ENERGY ($/KWH)			28
29	ON-PEAK	$0.44266		29
30	PART-PEAK		$0.19964	30
31	OFF-PEAK	$0.19288	$0.16141	31
32	SCHEDULE AG-5A			32
33	CUSTOMER CHARGE - RATES A & D ($/MONTH)	$17.47	$17.47	33
34	METER CHARGE - RATE A ($/MONTH)	$36.36	$36.36	34
35	METER CHARGE - RATE D ($/MONTH)	$161.58	$161.58	35
36	CONNECTED LOAD CHARGE ($/KW/MONTH)	$11.77	$2.19	36
37	ENERGY ($/KWH)			37
38	ON-PEAK	$0.30529		38
39	PART-PEAK		$0.16372	39
40	OFF-PEAK	$0.15541	$0.13833	40

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF JANUARY 1, 2017
AGRICULTURAL RATES

LINE NO.		1/1/17 RATES SUMMER	1/1/17 RATES WINTER	LINE NO.
1	SCHEDULE AG-1B			1
2	CUSTOMER CHARGE ($/MONTH)	$23.23	$23.23	2
3	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			3
4	SECONDARY VOLTAGE	$11.63	$2.34	4
5	PRIMARY VOLTAGE DISCOUNT	$1.21	$0.32	5
6	ENERGY CHARGE ($/KWH)	$0.23689	$0.18388	6
7	SCHEDULE AG-RB			7
8	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$23.23	$23.23	8
9	METER CHARGE - RATE B ($/MONTH)	$6.00	$6.00	9
10	METER CHARGE - RATE E ($/MONTH)	$1.20	$1.20	10
11	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$3.69		11
12	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			12
13	SECONDARY VOLTAGE	$9.59	$1.93	13
14	PRIMARY VOLTAGE DISCOUNT	$0.83	$0.31	14
15	ENERGY CHARGE ($/KWH)			15
16	ON-PEAK	$0.47286		16
17	PART-PEAK		$0.16207	17
18	OFF-PEAK	$0.17277	$0.13375	18
19	SCHEDULE AG-VB			19
20	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$23.23	$23.23	20
21	METER CHARGE - RATE B ($/MONTH)	$6.00	$6.00	21
22	METER CHARGE - RATE E ($/MONTH)	$1.20	$1.20	22
23	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$3.66		23
24	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			24
25	SECONDARY VOLTAGE	$9.65	$1.91	25
26	PRIMARY VOLTAGE DISCOUNT	$0.88	$0.30	26
27	ENERGY CHARGE ($/KWH)			27
28	ON-PEAK	$0.43817		28
29	PART-PEAK		$0.15943	29
30	OFF-PEAK	$0.16791	$0.13206	30

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF JANUARY 1, 2017

AGRICULTURAL RATES

LINE NO.		1/1/17 RATES SUMMER	1/1/17 RATES WINTER	LINE NO.
1	SCHEDULE AG-4B			1
2	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$23.23	$23.23	2
3	METER CHARGE - RATE B ($/MONTH)	$6.00	$6.00	3
4	METER CHARGE - RATE E ($/MONTH)	$1.20	$1.20	4
5	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$5.17		5
6	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			6
7	SECONDARY VOLTAGE	$9.79	$2.26	7
8	PRIMARY VOLTAGE DISCOUNT	$1.03	$0.35	8
9	ENERGY CHARGE ($/KWH)			9
10	ON-PEAK	$0.28935		10
11	PART-PEAK		$0.15568	11
12	OFF-PEAK	$0.15531	$0.13091	12
13	SCHEDULE AG-4C			13
14	CUSTOMER CHARGE - RATES C & F ($/MONTH)	$65.44	$65.44	14
15	METER CHARGE - RATE C ($/MONTH)	$6.00	$6.00	15
16	METER CHARGE - RATE F ($/MONTH)	$1.20	$1.20	16
17	DEMAND CHARGE ($/KW/MONTH)			17
18	ON-PEAK	$12.10		18
19	PART-PEAK	$2.31	$0.54	19
20	MAXIMUM	$4.96	$2.40	20
21	PRIMARY VOLTAGE DISCOUNT			21
22	ON-PEAK	$1.33		22
23	MAXIMUM		$0.31	23
24	TRANSMISSION VOLTAGE DISCOUNT			24
25	ON-PEAK	$6.31		25
26	PART-PEAK	$1.29	$0.54	26
27	MAXIMUM	$0.24	$1.66	27
28	ENERGY CHARGE ($/KWH)			28
29	ON-PEAK	$0.26389		29
30	PART-PEAK	$0.15461	$0.12898	30
31	OFF-PEAK	$0.11642	$0.11196	31
32	SCHEDULE AG-5B			32
33	CUSTOMER CHARGE - RATES B & E ($/MONTH)	$36.36	$36.36	33
34	METER CHARGE - RATE B ($/MONTH)	$6.00	$6.00	34
35	METER CHARGE - RATE E ($/MONTH)	$1.20	$1.20	35
36	ON-PEAK DEMAND CHARGE ($/KW/MONTH)	$9.85		36
37	MAXIMUM DEMAND CHARGE ($/KW/MONTH)			37
38	SECONDARY VOLTAGE	$15.37	$5.95	38
39	PRIMARY VOLTAGE DISCOUNT	$1.71	$0.18	39
40	TRANSMISSION VOLTAGE DISCOUNT	$11.49	$5.12	40
41	ENERGY CHARGE ($/KWH)			41
42	ON-PEAK	$0.20775		42
43	PART-PEAK		$0.10984	43
44	OFF-PEAK	$0.08974	$0.08143	44

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
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AGRICULTURAL RATES

LINE NO.		1/1/17 RATES SUMMER	1/1/17 RATES WINTER	LINE NO.
1	SCHEDULE AG-5C			1
2	CUSTOMER CHARGE - RATES C & F ($/MONTH)	$161.58	$161.58	2
3	METER CHARGE - RATE C ($/MONTH)	$6.00	$6.00	3
4	METER CHARGE - RATE F ($/MONTH)	$1.20	$1.20	4
5	DEMAND CHARGE ($/KW/MONTH)			5
6	ON-PEAK	$16.62		6
7	PART-PEAK	$3.44	$0.89	7
8	MAXIMUM	$5.95	$3.71	8
9	PRIMARY VOLTAGE DISCOUNT			9
10	ON-PEAK	$2.48		10
11	MAXIMUM		$0.25	11
12	TRANSMISSION VOLTAGE DISCOUNT			12
13	ON-PEAK	$10.30		13
14	PART-PEAK	$1.51	$0.89	14
15	MAXIMUM	$3.38	$2.43	15
16	ENERGY CHARGE ($/KWH)			16
17	ON-PEAK	$0.16019		17
18	PART-PEAK	$0.10958	$0.09639	18
19	OFF-PEAK	$0.09074	$0.08782	19
20	SCHEDULE AG-ICE			20
21	CUSTOMER CHARGE ($/MONTH)	$40.00	$40.00	21
22	METER CHARGE ($/MONTH)	$6.00	$6.00	22
23	ON-PEAK DEMAND CHARGE ($/KW/MO)	$6.95		23
24	MAXIMUM DEMAND CHARGE ($/KW/MO)			24
25	SECONDARY	$8.99	$0.00	25
26	PRIMARY	$7.85	$0.00	26
27	TRANSMISSION	$2.74	$0.00	27
28	ENERGY CHARGE ($/KWH)			28
29	ON-PEAK	$0.18415		29
30	PART-PEAK	$0.14364	$0.14732	30
31	OFF-PEAK	$0.07366	$0.07366	31

PACIFIC GAS AND ELECTRIC COMPANY
PRESENT ELECTRIC RATES
AS OF JANUARY 1, 2017

STREETLIGHTING RATES

LINE NO.		1/1/17 RATES SUMMER	1/1/17 RATES WINTER	LINE NO.
1	SCHEDULE LS-1			1
2	ENERGY CHARGE ($/KWH)	$0.15689	$0.15689	2
3	SCHEDULE LS-2			3
4	ENERGY CHARGE ($/KWH)	$0.15689	$0.15689	4
5	SCHEDULE LS-3			5
6	SERVICE CHARGE ($/METER/MO.)	$6.00	$6.00	6
7	ENERGY CHARGE ($/KWH)	$0.15689	$0.15689	7
8	SCHEDULE OL-1			8
9	ENERGY CHARGE ($/KWH)	$0.16414	$0.16414	9

Pacific Gas & Electric Company

2017 Annual Electric True-up (AET)

1/1/2017

ELECTRIC RATES FOR SCHEDULES LS-1, LS-2 AND OL-1

NOMINAL LAMP RATINGS			ALL NIGHT RATES PER LAMP PER MONTH									HALF-HOUR ADJ.	
	AVERAGE		SCHEDULE LS-2		SCHEDULE LS-1							LS-1 &	
LAMP WATTS	kWhr PER MONTH	INITIAL LUMENS	A	C	A	B	C	D	E	F	OL-1	LS-2	OL-1
MERCURY VAPOR LAMPS													
40	18	1,300	$3.031	--	--	--	--	--	--	--	--	$0.128	--
50	22	1,650	$3.659	--	--	--	--	--	--	--	--	$0.157	--
100	40	3,500	$6.483	$10.270	$12.790	--	$13.058	--	--	--	--	$0.285	--
175	68	7,500	$10.876	$14.663	$17.183	$17.183	$17.451	--	$21.147	$18.536	$17.676	$0.485	$0.507
250	97	11,000	$15.425	$19.212	$21.732	$21.732	$22.000	--	--	--	--	$0.692	--
400	152	21,000	$24.054	$27.841	$30.361	$30.361	$30.629	--	--	--	$31.463	$1.084	$1.134
700	266	37,000	$41.940	$45.727	$48.247	$48.247	$48.515	--	--	--	--	$1.897	--
1,000	377	57,000	$59.355	$63.142	--	--	--	--	--	--	--	$2.689	--
INCANDESCENT LAMPS													
58	20	600	$3.345	--	$9.652	--	--	--	--	--	--	$0.143	--
92	31	1,000	$5.071	$8.858	$11.378	--	--	--	--	--	--	$0.221	--
189	65	2,500	$10.405	$14.192	$16.712	$16.712	--	--	--	--	--	$0.464	--
295	101	4,000	$16.053	$19.840	$22.360	$22.360	--	--	--	--	--	$0.720	--
405	139	6,000	$22.015	$25.802	$28.322	--	--	--	--	--	--	$0.991	--
620	212	10,000	$33.468	$37.255	--	--	--	--	--	--	--	$1.512	--
860	294	15,000	$46.333	--	--	--	--	--	--	--	--	$2.097	--
LOW PRESSURE SODIUM VAPOR LAMPS													
35	21	4,800	$3.502	--	--	--	--	--	--	--	--	$0.150	--
55	29	8,000	$4.757	--	--	--	--	--	--	--	--	$0.207	--
90	45	13,500	$7.267	--	--	--	--	--	--	--	--	$0.321	--
135	62	21,500	$9.934	--	--	--	--	--	--	--	--	$0.442	--
180	78	33,000	$12.444	--	--	--	--	--	--	--	--	$0.556	--

Pacific Gas & Electric Company

2017 Annual Electric True-up (AET)

1/1/2017

ELECTRIC RATES FOR SCHEDULES LS-1, LS-2 AND OL-1

NOMINAL LAMP RATINGS			ALL NIGHT RATES PER LAMP PER MONTH									HALF-HOUR ADJ.	
LAMP	AVERAGE kWhr PER	INITIAL	SCHEDULE LS-2		SCHEDULE LS-1							LS-1 &	
WATTS	MONTH	LUMENS	A	C	A	B	C	D	E	F	OL-1	LS-2	OL-1
HIGH PRESSURE SODIUM VAPOR LAMPS													
AT 120 VOLTS													
35	15	2,150	$2.560	--	--	--	--	--	--	--	--	$0.107	--
50	21	3,800	$3.502	--	--	--	--	--	--	--	--	$0.150	--
70	29	5,800	$4.757	$8.544	$11.064	--	$11.332	$14.273	$15.028	$12.417	$11.274	$0.207	$0.216
100	41	9,500	$6.639	$10.426	$12.946	--	$13.214	$16.155	$16.910	$14.299	$13.244	$0.292	$0.306
150	60	16,000	$9.620	$13.407	$15.927	--	$16.195	$19.136	$19.891	$17.280	--	$0.428	--
200	80	22,000	$12.758	--	$19.065	--	$19.333	$22.274	$23.029	$20.418	--	$0.571	--
250	100	26,000	$15.896		$22.203	--	$22.471	$25.412	$26.167	$23.556		$0.713	
400	154	46,000	$24.368		$30.675	--	$30.943	$33.884	$34.639	$32.028		$1.098	
AT 240 VOLTS													
50	24	3,800	$3.972	--	--	--	--	--	--	--	--	$0.171	--
70	34	5,800	$5.541	$9.328	$11.848	--	--	$15.057	--	--	--	$0.242	--
100	47	9,500	$7.581	$11.368	$13.888	--	$14.156	$17.097	$17.852	$15.241	--	$0.335	--
150	69	16,000	$11.032	$14.819	$17.339	--	$17.607	$20.548	$21.303	$18.692	--	$0.492	--
200	81	22,000	$12.915	$16.702	$19.222	--	$19.490	$22.431	$23.186	$20.575	$19.809	$0.578	$0.604
250	100	25,500	$15.896	$19.683	$22.203	--	$22.471	$25.412	$26.167	$23.556	$22.928	$0.713	$0.746
310	119	37,000	$18.877	--	--	--	--	--	--	--	--	$0.849	--
360	144	45,000	$22.799	--	--	--	--	--	--	--	--	$1.027	--
400	154	46,000	$24.368	$28.155	$30.675	--	$30.943	$33.884	$34.639	$32.028	$31.792	$1.098	$1.149
METAL HALIDE LAMPS													
70	30	5,500	$4.914	--	--	--	--	--	--	--	--	$0.214	--
100	41	8,500	$6.639	--	--	--	--	--	--	--	--	$0.292	--
150	63	13,500	$10.091	--	--	--	--	--	--	--	--	$0.449	--
175	72	14,000	$11.503	--	--	--	--	--	--	--	--	$0.513	--
250	105	20,500	$16.680	--	--	--	--	--	--	--	--	$0.749	--
400	162	30,000	$25.623	--	--	--	--	--	--	--	--	$1.155	--
1,000	387	90,000	$60.923	--	--	--	--	--	--	--	--	$2.760	--
INDUCTION LAMPS													
23	9	1,840	$1.619	--	--	--	--	--	--	--	--	$0.064	--
35	13	2,450	$2.247	--	--	--	--	--	--	--	--	$0.093	--
40	14	2,200	$2.403	--	--	--	--	--	--	--	--	$0.100	--
50	18	3,500	$3.031	--	--	--	--	--	--	--	--	$0.128	--
55	19	3,000	$3.188	--	--	--	--	--	--	--	--	$0.136	--

Pacific Gas & Electric Company

2017 Annual Electric True-up (AET)

1/1/2017

ELECTRIC RATES FOR SCHEDULES LS-1, LS-2 AND OL-1

NOMINAL LAMP RATINGS			ALL NIGHT RATES PER LAMP PER MONTH									HALF-HOUR ADJ.	
	AVERAGE		SCHEDULE LS-2		SCHEDULE LS-1							LS-1 &	
LAMP WATTS	kWhr PER MONTH	INITIAL LUMENS	A	C	A	B	C	D	E	F	OL-1	LS-2	OL-1
65	24	5,525	$3.972	--	--	--	--	--	--	--	--	$0.171	--
70	27	6,500	$4.443	--	--	--	--	--	--	--	--	$0.193	--
80	28	4,500	$4.600	--	--	--	--	--	--	--	--	$0.200	--
85	30	4,800	$4.914	--	--	--	--	--	--	--	--	$0.214	--
100	36	8,000	$5.855	--	--	--	--	--	--	--	--	$0.257	--
120	42	8,500	$6.720	--	--	--	--	--	--	--	--	$0.296	--
135	48	9,450	$7.738	--	--	--	--	--	--	--	--	$0.342	--
150	51	10,900	$8.208	--	--	--	--	--	--	--	--	$0.364	--
165	58	12,000	$9.307	--	--	--	--	--	--	--	--	$0.414	--
200	72	19,000	$11.503	--	--	--	--	--	--	--	--	$0.513	--

All LEDs now on separate tab.

Energy Rate @	$0.15689	per kwh	LS-1 & LS-2
	$0.16414	per kwh	OL-1

Pole Painting Charge @ Per Pole Per Month

27-Dec-16

Pacific Gas & Electric Company
2017 Annual Electric True-up (AET)
1/1/17
LIGHT EMITTING DIODE (LED) LAMPS
TOTAL RATES (FACILITY + ENERGY CHGS)

NOMINAL LAMP RATINGS		ALL NIGHT RATES PER LAMP PER MONTH	HALF-HOUR ADJUSTMENT	ALL NIGHT RATES PER LAMP PER MONTH				
Lamp Watts	Average kWh Per Month	LS-2A	LS-1A, C, E, F & LS-2A	LS-1A	LS-1C	LS-1D	LS-1E	LS-1F
0.0-5.0	0.9	$0.348	$0.006	$6.655	$6.923	$9.864	$10.619	$8.008
5.1-10.0	2.6	$0.615	$0.019	$6.922	$7.190	$10.131	$10.886	$8.275
10.1-15.0	4.3	$0.882	$0.031	$7.189	$7.457	$10.398	$11.153	$8.542
15.1-20.0	6.0	$1.148	$0.043	$7.455	$7.723	$10.664	$11.419	$8.808
20.1-25.0	7.7	$1.415	$0.055	$7.722	$7.990	$10.931	$11.686	$9.075
25.1-30.0	9.4	$1.682	$0.067	$7.989	$8.257	$11.198	$11.953	$9.342
30.1-35.0	11.1	$1.948	$0.079	$8.255	$8.523	$11.464	$12.219	$9.608
35.1-.40.0	12.8	$2.215	$0.091	$8.522	$8.790	$11.731	$12.486	$9.875
40.1-45.0	14.5	$2.482	$0.103	$8.789	$9.057	$11.998	$12.753	$10.142
45.1-50.0	16.2	$2.749	$0.116	$9.056	$9.324	$12.265	$13.020	$10.409
50.1-55.0	17.9	$3.015	$0.128	$9.322	$9.590	$12.531	$13.286	$10.675
55.1-60.0	19.6	$3.282	$0.140	$9.589	$9.857	$12.798	$13.553	$10.942
60.1-65.0	21.4	$3.564	$0.153	$9.871	$10.139	$13.080	$13.835	$11.224
65.1-70.0	23.1	$3.831	$0.165	$10.138	$10.406	$13.347	$14.102	$11.491
70.1-75.0	24.8	$4.098	$0.177	$10.405	$10.673	$13.614	$14.369	$11.758
75.1-80.0	26.5	$4.365	$0.189	$10.672	$10.940	$13.881	$14.636	$12.025
80.1-85.0	28.2	$4.631	$0.201	$10.938	$11.206	$14.147	$14.902	$12.291
85.1-90.0	29.9	$4.898	$0.213	$11.205	$11.473	$14.414	$15.169	$12.558
90.1-95.0	31.6	$5.165	$0.225	$11.472	$11.740	$14.681	$15.436	$12.825
95.1-100.0	33.3	$5.431	$0.237	$11.738	$12.006	$14.947	$15.702	$13.091
100.1-105.1	35.0	$5.698	$0.250	$12.005	$12.273	$15.214	$15.969	$13.358
105.1-110.0	36.7	$5.965	$0.262	$12.272	$12.540	$15.481	$16.236	$13.625
110.1-115.0	38.4	$6.232	$0.274	$12.539	$12.807	$15.748	$16.503	$13.892
115.1-120.0	40.1	$6.498	$0.286	$12.805	$13.073	$16.014	$16.769	$14.158
120.1-125.0	41.9	$6.781	$0.299	$13.088	$13.356	$16.297	$17.052	$14.441
125.1-130.0	43.6	$7.047	$0.311	$13.354	$13.622	$16.563	$17.318	$14.707
130.1-135.0	45.3	$7.314	$0.323	$13.621	$13.889	$16.830	$17.585	$14.974
135.1-140.0	47.0	$7.581	$0.335	$13.888	$14.156	$17.097	$17.852	$15.241
140.1-145.0	48.7	$7.848	$0.347	$14.155	$14.423	$17.364	$18.119	$15.508
145.1-150.0	50.4	$8.114	$0.359	$14.421	$14.689	$17.630	$18.385	$15.774
150.1-155.0	52.1	$8.381	$0.372	$14.688	$14.956	$17.897	$18.652	$16.041
155.1-160.0	53.8	$8.648	$0.384	$14.955	$15.223	$18.164	$18.919	$16.308
160.1-165.0	55.5	$8.914	$0.396	$15.221	$15.489	$18.430	$19.185	$16.574
165.1-170.0	57.2	$9.181	$0.408	$15.488	$15.756	$18.697	$19.452	$16.841
170.1-175.0	58.9	$9.448	$0.420	$15.755	$16.023	$18.964	$19.719	$17.108
175.1-180.0	60.6	$9.715	$0.432	$16.022	$16.290	$19.231	$19.986	$17.375
180.1-185.0	62.4	$9.997	$0.445	$16.304	$16.572	$19.513	$20.268	$17.657
185.1-190.0	64.1	$10.264	$0.457	$16.571	$16.839	$19.780	$20.535	$17.924
190.1-195.0	65.8	$10.530	$0.469	$16.837	$17.105	$20.046	$20.801	$18.190
195.1-200.0	67.5	$10.797	$0.481	$17.104	$17.372	$20.313	$21.068	$18.457
200.1-205.0	69.2	$11.064	$0.494	$17.371	$17.639	$20.580	$21.335	$18.724
205.1-210.0	70.9	$11.331	$0.506	$17.638	$17.906	$20.847	$21.602	$18.991
210.1-215.0	72.6	$11.597	$0.518	$17.904	$18.172	$21.113	$21.868	$19.257
215.1-220.0	74.3	$11.864	$0.530	$18.171	$18.439	$21.380	$22.135	$19.524
220.1-225.0	76.0	$12.131	$0.542	$18.438	$18.706	$21.647	$22.402	$19.791
225.1-230.0	77.7	$12.397	$0.554	$18.704	$18.972	$21.913	$22.668	$20.057
230.1-235.0	79.4	$12.664	$0.566	$18.971	$19.239	$22.180	$22.935	$20.324
235.1-240.0	81.1	$12.931	$0.578	$19.238	$19.506	$22.447	$23.202	$20.591

LIGHT EMITTING DIODE (LED) LAMPS CONVERSION
(with LED Surcharge)

Lamp Watts	ALL NIGHT RATES PER LAMP PER MONTH					HALF-HOUR ADJUSTMENT
	LS-1A	LS-1C	LS-1D	LS-1E	LS-1F	LS-1A, C, D, E & F
0.0-5.0	$9.469	$9.737	$22.632	$13.433	$10.822	$0.006
5.1-10.0	$9.736	$10.004	$22.899	$13.700	$11.089	$0.019
10.1-15.0	$10.003	$10.271	$23.166	$13.967	$11.356	$0.031
15.1-20.0	$10.269	$10.537	$23.432	$14.233	$11.622	$0.043
20.1-25.0	$10.536	$10.804	$23.699	$14.500	$11.889	$0.055
25.1-30.0	$10.803	$11.071	$23.966	$14.767	$12.156	$0.067
30.1-35.0	$11.069	$11.337	$24.232	$15.033	$12.422	$0.079
35.1-.40.0	$11.336	$11.604	$24.499	$15.300	$12.689	$0.091
40.1-45.0	$11.603	$11.871	$24.766	$15.567	$12.956	$0.103
45.1-50.0	$11.870	$12.138	$25.033	$15.834	$13.223	$0.116
50.1-55.0	$12.136	$12.404	$25.299	$16.100	$13.489	$0.128
55.1-60.0	$12.403	$12.671	$25.566	$16.367	$13.756	$0.140
60.1-65.0	$12.685	$12.953	$25.848	$16.649	$14.038	$0.153
65.1-70.0	$12.952	$13.220	$26.115	$16.916	$14.305	$0.165
70.1-75.0	$13.219	$13.487	$26.382	$17.183	$14.572	$0.177
75.1-80.0	$13.486	$13.754	$26.649	$17.450	$14.839	$0.189
80.1-85.0	$13.752	$14.020	$26.915	$17.716	$15.105	$0.201
85.1-90.0	$14.019	$14.287	$27.182	$17.983	$15.372	$0.213
90.1-95.0	$14.286	$14.554	$27.449	$18.250	$15.639	$0.225
95.1-100.0	$14.552	$14.820	$27.715	$18.516	$15.905	$0.237
100.1-105.1	$14.819	$15.087	$27.982	$18.783	$16.172	$0.250
105.1-110.0	$15.086	$15.354	$28.249	$19.050	$16.439	$0.262
110.1-115.0	$15.353	$15.621	$28.516	$19.317	$16.706	$0.274
115.1-120.0	$15.619	$15.887	$28.782	$19.583	$16.972	$0.286
120.1-125.0	$15.902	$16.170	$29.065	$19.866	$17.255	$0.299
125.1-130.0	$16.168	$16.436	$29.331	$20.132	$17.521	$0.311
130.1-135.0	$16.435	$16.703	$29.598	$20.399	$17.788	$0.323
135.1-140.0	$16.702	$16.970	$29.865	$20.666	$18.055	$0.335
140.1-145.0	$16.969	$17.237	$30.132	$20.933	$18.322	$0.347
145.1-150.0	$17.235	$17.503	$30.398	$21.199	$18.588	$0.359
150.1-155.0	$17.502	$17.770	$30.665	$21.466	$18.855	$0.372
155.1-160.0	$17.769	$18.037	$30.932	$21.733	$19.122	$0.384
160.1-165.0	$18.035	$18.303	$31.198	$21.999	$19.388	$0.396
165.1-170.0	$18.302	$18.570	$31.465	$22.266	$19.655	$0.408
170.1-175.0	$18.569	$18.837	$31.732	$22.533	$19.922	$0.420
175.1-180.0	$18.836	$19.104	$31.999	$22.800	$20.189	$0.432
180.1-185.0	$19.118	$19.386	$32.281	$23.082	$20.471	$0.445
185.1-190.0	$19.385	$19.653	$32.548	$23.349	$20.738	$0.457
190.1-195.0	$19.651	$19.919	$32.814	$23.615	$21.004	$0.469
195.1-200.0	$19.918	$20.186	$33.081	$23.882	$21.271	$0.481
200.1-205.0	$20.185	$20.453	$33.348	$24.149	$21.538	$0.494
205.1-210.0	$20.452	$20.720	$33.615	$24.416	$21.805	$0.506
210.1-215.0	$20.718	$20.986	$33.881	$24.682	$22.071	$0.518
215.1-220.0	$20.985	$21.253	$34.148	$24.949	$22.338	$0.530
220.1-225.0	$21.252	$21.520	$34.415	$25.216	$22.605	$0.542
225.1-230.0	$21.518	$21.786	$34.681	$25.482	$22.871	$0.554
230.1-235.0	$21.785	$22.053	$34.948	$25.749	$23.138	$0.566
235.1-240.0	$22.052	$22.320	$35.215	$26.016	$23.405	$0.578

240.1-245.0	82.9	$13.213	$0.591	$19.520	$19.788	$22.729	$23.484	$20.873	$22.334	$22.602	$35.497	$26.298	$23.687	$0.591
245.1-250.0	84.6	$13.480	$0.603	$19.787	$20.055	$22.996	$23.751	$21.140	$22.601	$22.869	$35.764	$26.565	$23.954	$0.603
250.1-255.0	86.3	$13.747	$0.615	$20.054	$20.322	$23.263	$24.018	$21.407	$22.868	$23.136	$36.031	$26.832	$24.221	$0.615
255.1-260.0	88.0	$14.013	$0.628	$20.320	$20.588	$23.529	$24.284	$21.673	$23.134	$23.402	$36.297	$27.098	$24.487	$0.628
260.1-265.0	89.7	$14.280	$0.640	$20.587	$20.855	$23.796	$24.551	$21.940	$23.401	$23.669	$36.564	$27.365	$24.754	$0.640
265.1-270.0	91.4	$14.547	$0.652	$20.854	$21.122	$24.063	$24.818	$22.207	$23.668	$23.936	$36.831	$27.632	$25.021	$0.652
270.1-275.0	93.1	$14.813	$0.664	$21.120	$21.388	$24.329	$25.084	$22.473	$23.934	$24.202	$37.097	$27.898	$25.287	$0.664
275.1-280.0	94.8	$15.080	$0.676	$21.387	$21.655	$24.596	$25.351	$22.740	$24.201	$24.469	$37.364	$28.165	$25.554	$0.676
280.1-285.0	96.5	$15.347	$0.688	$21.654	$21.922	$24.863	$25.618	$23.007	$24.468	$24.736	$37.631	$28.432	$25.821	$0.688
285.1-290.0	98.2	$15.614	$0.700	$21.921	$22.189	$25.130	$25.885	$23.274	$24.735	$25.003	$37.898	$28.699	$26.088	$0.700
290.1-295.0	99.9	$15.880	$0.712	$22.187	$22.455	$25.396	$26.151	$23.540	$25.001	$25.269	$38.164	$28.965	$26.354	$0.712
295.1-300.0	101.6	$16.147	$0.725	$22.454	$22.722	$25.663	$26.418	$23.807	$25.268	$25.536	$38.431	$29.232	$26.621	$0.725
300.1-305.0	103.4	$16.429	$0.737	$22.736	$23.004	$25.945	$26.700	$24.089	$25.550	$25.818	$38.713	$29.514	$26.903	$0.737
305.1-310.0	105.1	$16.696	$0.750	$23.003	$23.271	$26.212	$26.967	$24.356	$25.817	$26.085	$38.980	$29.781	$27.170	$0.750
310.1-315.0	106.8	$16.963	$0.762	$23.270	$23.538	$26.479	$27.234	$24.623	$26.084	$26.352	$39.247	$30.048	$27.437	$0.762
315.1-320.0	108.5	$17.230	$0.774	$23.537	$23.805	$26.746	$27.501	$24.890	$26.351	$26.619	$39.514	$30.315	$27.704	$0.774
320.1-325.0	110.2	$17.496	$0.786	$23.803	$24.071	$27.012	$27.767	$25.156	$26.617	$26.885	$39.780	$30.581	$27.970	$0.786
325.1-330.0	111.9	$17.763	$0.798	$24.070	$24.338	$27.279	$28.034	$25.423	$26.884	$27.152	$40.047	$30.848	$28.237	$0.798
330.1-335.0	113.6	$18.030	$0.810	$24.337	$24.605	$27.546	$28.301	$25.690	$27.151	$27.419	$40.314	$31.115	$28.504	$0.810
335.1-340.0	115.3	$18.296	$0.822	$24.603	$24.871	$27.812	$28.567	$25.956	$27.417	$27.685	$40.580	$31.381	$28.770	$0.822
340.1-345.0	117.0	$18.563	$0.834	$24.870	$25.138	$28.079	$28.834	$26.223	$27.684	$27.952	$40.847	$31.648	$29.037	$0.834
345.1-350.0	118.7	$18.830	$0.847	$25.137	$25.405	$28.346	$29.101	$26.490	$27.951	$28.219	$41.114	$31.915	$29.304	$0.847
350.1-355.0	120.4	$19.097	$0.859	$25.404	$25.672	$28.613	$29.368	$26.757	$28.218	$28.486	$41.381	$32.182	$29.571	$0.859
355.1-360.0	122.1	$19.363	$0.871	$25.670	$25.938	$28.879	$29.634	$27.023	$28.484	$28.752	$41.647	$32.448	$29.837	$0.871
360.1-365.0	123.9	$19.646	$0.884	$25.953	$26.221	$29.162	$29.917	$27.306	$28.767	$29.035	$41.930	$32.731	$30.120	$0.884
365.1-370.0	125.6	$19.912	$0.896	$26.219	$26.487	$29.428	$30.183	$27.572	$29.033	$29.301	$42.196	$32.997	$30.386	$0.896
370.1-375.0	127.3	$20.179	$0.908	$26.486	$26.754	$29.695	$30.450	$27.839	$29.300	$29.568	$42.463	$33.264	$30.653	$0.908
375.1-380.0	129.0	$20.446	$0.920	$26.753	$27.021	$29.962	$30.717	$28.106	$29.567	$29.835	$42.730	$33.531	$30.920	$0.920
380.1-385.0	130.7	$20.713	$0.932	$27.020	$27.288	$30.229	$30.984	$28.373	$29.834	$30.102	$42.997	$33.798	$31.187	$0.932
385.1-390.0	132.4	$20.979	$0.944	$27.286	$27.554	$30.495	$31.250	$28.639	$30.100	$30.368	$43.263	$34.064	$31.453	$0.944
390.1-395.0	134.1	$21.246	$0.956	$27.553	$27.821	$30.762	$31.517	$28.906	$30.367	$30.635	$43.530	$34.331	$31.720	$0.956
395.1-400.0	135.8	$21.513	$0.968	$27.820	$28.088	$31.029	$31.784	$29.173	$30.634	$30.902	$43.797	$34.598	$31.987	$0.968

LED lights are only applicable to LS-1A, 1C, 1E and 1F

Decorative LED lights are only applicable to LS-1D

EXHIBIT 3

SERVICE OF NOTICE OF APPLICATION

In accordance with Rule 3.2(b), Applicant will mail a notice to the following, stating in general terms its proposed change in rates.

State of California

To the Attorney General and the Department of General Services.

State of California
Office of Attorney General
1300 I St Ste 1101
Sacramento, CA 95814

and

Department of General Services
Office of Buildings & Grounds
505 Van Ness Avenue, Room 2012
San Francisco, CA 94102

Counties

To the County Counsel or District Attorney and the County Clerk in the following counties:

Alameda	Mariposa	Santa Clara
Alpine	Mendocino	Santa Cruz
Amador	Merced	Shasta
Butte	Modoc	Sierra
Calaveras	Monterey	Siskiyou
Colusa	Napa	Solano
Contra Costa	Nevada	Sonoma
El Dorado	Placer	Stanislaus
Fresno	Plumas	Sutter
Glenn	Sacramento	Tehama
Humboldt	San Benito	Trinity
Kern	San Bernardino	Tulare
Kings	San Francisco	Tuolumne
Lake	San Joaquin	Yolo
Lassen	San Luis Obispo	Yuba
Madera	San Mateo	
Marin	Santa Barbara	

Municipal Corporations

To the City Attorney and the City Clerk of the following municipal corporations:

Alameda
Albany
Amador City
American Canyon
Anderson
Angels Camp
Antioch
Arcata
Arroyo Grande
Arvin
Atascadero
Atherton
Atwater
Auburn
Avenal
Bakersfield
Barstow
Belmont
Belvedere
Benicia
Berkeley
Biggs
Blue Lake
Brentwood
Brisbane
Buellton
Burlingame
Calistoga
Campbell
Capitola
Carmel
Ceres
Chico
Chowchilla
Citrus Heights
Clayton
Clearlake
Cloverdale
Clovis
Coalinga
Colfax
Colma
Colusa
Concord
Corcoran
Corning
Corte Madera
Cotati
Cupertino
Daly City
Danville
Davis
Del Rey Oakes
Dinuba
Dixon
Dos Palos
Dublin
East Palo Alto
El Cerrito
Elk Grove
Emeryville
Escalon
Eureka
Fairfax
Fairfield
Ferndale
Firebaugh
Folsom
Fort Bragg
Fortuna
Foster City
Fowler
Fremont
Fresno
Galt
Gilroy
Gonzales
Grass Valley
Greenfield
Gridley
Grover Beach
Guadalupe
Gustine
Half Moon Bay
Hanford
Hayward
Healdsburg
Hercules
Hillsborough
Hollister
Hughson
Huron
Ione
Isleton
Jackson
Kerman
King City
Kingsburg
Lafayette
Lakeport
Larkspur
Lathrop
Lemoore
Lincoln
Live Oak
Livermore
Livingston
Lodi
Lompoc
Loomis
Los Altos
Los Altos Hills
Los Banos
Los Gatos
Madera
Manteca
Maricopa
Marina
Mariposa
Martinez
Marysville
McFarland
Mendota
Menlo Park
Merced
Mill Valley

Millbrae
Milpitas
Modesto
Monte Sereno
Monterey
Moraga
Morgan Hill
Morro Bay
Mountain View
Napa
Newark
Nevada City
Newman
Novato
Oakdale
Oakland
Oakley
Orange Cove
Orinda
Orland
Oroville
Pacific Grove
Pacifica
Palo Alto
Paradise
Parlier
Paso Robles
Patterson
Petaluma
Piedmont
Pinole
Pismo Beach
Pittsburg
Placerville
Pleasant Hill
Pleasanton
Plymouth
Point Arena
Portola
Portola Valley
Rancho Cordova
Red Bluff
Redding
Redwood City
Reedley
Richmond
Ridgecrest
Rio Dell
Rio Vista
Ripon
Riverbank
Rocklin
Rohnert Park
Roseville
Ross
Sacramento
Saint Helena
Salinas
San Anselmo
San Bruno
San Carlos
San Francisco
San Joaquin
San Jose
San Juan Bautista
San Leandro
San Luis Obispo
San Mateo
San Pablo
San Rafael
San Ramon
Sand City
Sanger
Santa Clara
Santa Cruz
Santa Maria
Santa Rosa
Saratoga
Sausalito
Scotts Valley
Seaside
Sebastopol
Selma
Shafter
Shasta Lake
Soledad
Solvang
Sonoma
Sonora
South San Francisco
Stockton
Suisun City
Sunnyvale
Sutter Creek
Taft
Tehama
Tiburon
Tracy
Trinidad
Turlock
Ukiah
Union City
Vacaville
Vallejo
Victorville
Walnut Creek
Wasco
Waterford
Watsonville
West Sacramento
Wheatland
Williams
Willits
Willows
Windsor
Winters
Woodland
Woodside
Yountville
Yuba City